TIDAL POWER STUDY
COBSCOOK BAY, MAINE

REPORT OF THE

SYMPOSIUM ON RELATIVE PRICE SHIFT ANALYSIS AS APPLIED TO PUBLIC POWER PROJECTS

HELD AT PORTLAND, MAINE

NOVEMBER 1979

United States Army
Corps of Engineers
... Serving the Army
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New England Division

REPORT OF THE

"Symposium on Relative Price Shift Analysis
as Applied to Public Power Projects"

Held at

The University of Southern Maine
Center for Research and Advanced Study

Portland, Maine

November 27, 1979

Sponsored by

Project on Balanced Growth for Maine
University of Maine at Orono

Maine Office of Energy Resources

Maine State Planning Office

U.S. Army Corps of Engineers
New England Division

Forward

In March of 1979, the U.S. Army Corps of Engineers, New England Division, completed preliminary economic analysis for several tidal power alternatives at Cobscook Bay, Maine. The report contained conventional benefit-to-cost analysis based on Federal Energy Regulatory Commission power values, as well as an innovative dynamic benefit-to-cost analysis based on "relative price shift analysis." Relative price shift analysis considers differential price changes among commodities without including the effect of general inflation.

Since relative price shift analysis had never been used by the Federal Government prior to that report, the Corps was concerned about the theoretical acceptability of the concept. In an attempt to ascertain the feelings of the academic and industrial community with respect to the method, the Corps entered into a contract with the University of Maine, Project on Balanced Growth, to conduct a conference on Relative Price Shift Analysis for Public Power Projects.

This report, compiled at the University of Maine, Orono, under the direction of Professor Arthur M. Johnson, summarizes the results of a Symposium conducted at Portland, Maine, on 27 November 1979.

The findings of the conference were not definitive. Generally, it was agreed by most panelists that relative price shift analysis was an improvement over conventional analysis, but due to the complexity of projecting fuel cost, environmental costs, social costs and technological displacement, the method should be applied with a great deal of caution.

TABLE OF CONTENTS

Introduction

The era of cheap energy based on petroleum has come to an end in the United States. This fact has had major repercussions on the American economy nationally and on New England's in particular, since this region has depended heavily on imported foreign oil to power its factories and electric generating plants, and to heat its homes. The search for alternative sources of energy has gathered momentum as the price of petroleum has escalated. Among the relatively unique electrical energy alternatives available to New England is tidal power. Interest in this source of energy goes back to 1919 when Dexter P. Cooper, an eminent engineer of the day, first envisioned a project, to the mid-1930's when an all-United States tidal power project was initiated by Franklin D. Roosevelt's New Deal, utilizing Cobscook Bay. Given the low price of other energy sources at that time, the Passamaquoddy project, as it was known, was not perceived as an economic one and was abandoned in its early stages. A similar conclusion was reached in 1961 regarding a large-scale international project which involved both Cobscook (U.S.) and Passamaquoddy (Canadian) Bays. Not until the recent past did the economics of energy appear to be shifting sufficiently to suggest a possibility that a project of this type might now be justified. The new study of this possibility by the U.S. Army Corps of Engineers was confined to an all-United States project based on Cobscook Bay in the vicinity of Eastport, Maine.

How to evaluate a public power project from an economic standpoint is a crucial question. Clearly, the earlier Cobscook Bay and Passamaquoddy Bay projects would, from today's perspective, have been more than economically justified. But decisions to build them had to be made at that time, not forty years later. The U.S. Army Corps of Engineers, which is charged by law with evaluating projects of this kind, must reach decisions on public capital investments that have a life expectancy of 30 to 100 years. Basically, its approach has been to relate projected benefits to projected costs. Obviously, decisions based on current prices may produce misleading results, especially when the economy is experiencing double-digit inflation. One approach has been to look at the benefit-cost relationship over the life of the project--the so-called "conventional" economic analysis. However, using this approach with current prices and not taking into account the fact that competing forms of energy may over the long run change in price at different rates can also produce misleading results. The basic problem, in other words, is that sunk construction costs of a power project are incurred in the short term, but the benefits are only realized over the long run.

To take account of these variables, the U.S. Army Corps of Engineers, New England Division, adopted a refined life cycle analysis method known as "relative price shift" analysis to evaluate the Cobscook Bay tidal power proposal. Relative price shift analysis excludes general inflation which is inherent to "life cycle analysis". Although the results of this study as of mid-1979 did not economically justify the undertaking, the New England Division was anxious to obtain an objective and scholarly evaluation of the validity of the methodology employed. Since the University of Maine at Orono had been involved in organizing and conducting several public participation programs for the Division, it was asked, through the Project on Balanced Growth for Maine, to organize a symposium on relative price shift analysis featuring short papers by academic, industry and government experts. Subsequently, the Maine State Planning Office and the Maine Office of Energy Resources joined in sponsoring the symposium.

A meeting of interested parties in Augusta, Maine, in mid-October 1979, planned the symposium, which was scheduled for November 27, 1979, at the Center for Research and Advanced Study at the University of Southern Maine. At the steering committee meeting, it was agreed that emphasis would be placed on methodology, not its application to a specific situation like Cobscook Bay. The subjects of the papers that constitute the bulk of this report were identified and agreement was reached on those qualified to prepare them.

Philip C. Hastings, Research Engineer for the Central Maine Power Company, was asked to prepare a paper on economic considerations involved in the evaluation of hydroelectric projects. His paper focused on the importance of the assumptions used and the procedures employed, and he differentiated between large and small projects.

The next paper, by Charles Colgan of the Maine State Planning Office, examined the question of how comparisons should be structured for relative price shift purposes and pointed out some of the difficulties in doing this properly. For example: What are realistic alternatives? How well can we forecast future oil prices? How do we assess the impact of new technologies and compare them with known technologies? He also pointed out that environmental impacts had to be considered in assessing the real cost of a project.

The third paper, by Professor Lawrence G. Hines of Dartmouth College, addressed the issue of how the benefit-cost ratio might be affected by (1) the choice of alternatives with which to compare a project under consideration, or by (2) the inclusion of ancillary benefits, such as recreational boating to produce a stronger benefit-to-cost ratio.

The fourth paper, by William H. Beardsley, assistant to the President of the Bangor Hydro-Electric Company, dealt with various theoretical and real problems of applying relative price shift analysis. While endorsing the approach, he identified some of the variables that have to be handled carefully, such as the discount rate applied to public as compared to private investment in comparable facilities. He noted the difficulties of forecasting price shifts three decades out, the possibilities of new technologies affecting the future energy situation, and the like. In his view, while the relative price shift approach is theoretically sound, it is only one way of evaluating power projects and--for the reasons stated--is probably more valid for the shorter run, say 30 years, than for the entire life of a hydroelectric project.

Gerald G. Dawbin of the Maine State ENERGY Office continued the evaluation of relative price shift methodology by stressing the important of selecting realistic alternatives in evaluating a power project and argued that the most appropriate comparison for a tidal power project would be the oil that it displaced for electrical generation.

Dr. Normand Laberge contributed a paper on life-cycle cost analysis versus relative price shift, drawing on the small-scale Half-Moon Cove tidal project as a case in point. His relatively technical presentation was especially concerned with the impact of inflation on project evaluations.

Professor A. Myrick Freeman III of Bowdoin College addressed the question of establishing an appropriate discount rate in evaluating public power projects. He argued that the appropriate rate for federally funded projects should not be an arbitrary figure made possible by the unique financial position of the government; instead, it should be the real opportunity cost of private investment. The discount rate, as he saw it, should include a risk premium but no inflationary premium.

Professor William D. Shipman of Bowdoin College concluded the panel presentation with a paper on identification of the appropriate measure of benefits in evaluating tidal power in Cobscook Bay. He ruled out inclusion of "capacity" benefits, since the single-pool tidal power system proposed does not constitute "dependable" power in the sense that a two-pool system or other alternatives do. In assessing the energy benefits of Cobscook tidal power, Professor Shipman, like Mr. Dawbin, argued that realistically the alternative in New England is electricity generated with OPEC oil.

After a short break, discussion of these papers from the floor and among the panelists was encouraged, with Dr. Arthur M. Johnson, University of Maine at Orono, acting as Moderator. The report of Sharon Graves Floyd, who acted as recorder of the discussion along with Wayne Oliver of the New England Regional Commission, follows the panelists' papers.

The symposium meeting adjourned at 5:00 PM and was followed by an informal post-symposium evaluation session. The consensus of the panelists and representatives of the U.S. Army Corps of Engineers was that the papers had addressed meaningful questions, and, considering the amount of time available to prepare them, had contributed importantly to understanding the strengths and weaknesses of the methodology. The net conclusion appeared to be that relative price shift analysis has much to recommend it over present static economic evaluation procedures. However, it is only one of several methodologies that should be applied and, like all methodologies, the results are significantly affected by what is included and how it is included. The panelists contributed significantly to identifying these specific elements, and the sponsors of the symposium are especially grateful for these insights, provided on short notice to meet a real need. The cooperation of the University of Southern Maine and the New England Division, U.S. Army Corps of Engineers, was also important to the success of the symposium.

Arthur M. Johnson, Director
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Background Information

This section is made up of two briefing documents given to the University of Maine by the Corps of Engineers for distribution to the panelists prior to the preparation of their papers for the conference.

The first entitled "Background Material" is a very brief summary of various aspects and methods used for conducting economic analysis of the Cobscook Bay Tidal Power Project. The second document entitled "Relative Price Shift Analysis" is a reprint of Chapter 4 of a report entitled "Tidal Power Study, Cobscook Bay, Maine - Preliminary Report on the Economic Analysis of the Project" March 1979. This presents a more detailed explanation of "relative price shift analysis".

Tidal Power Study
Cobscook Bay, Maine

BACKGROUND MATERIAL

for discussions on the

Preliminary Report on the Economic
Analysis of the Project

September 1979

U. S. Army Engineer Division, New England
424 Trapelo Road
Waltham, Massachusetts 02154

Contents

THE ALTERNATIVE COST PRINCIPLE

The justification for authorization of all Corps of Engineers projects is measured in terms of the benefit to cost ratio. The economic analysis, which defines the economic worth of the project, is based on standards prescribed by the Water Resource Council in the Principles and Standards for Planning Water and Related Land Resources.

Power benefits are measured by the cost of power from the most likely alternative source (the most feasible privately financed equivalent alternative source in this case). Unit power values (benefits) for capacity and energy are furnished by the Federal Energy Regulatory Commission (formerly Federal Power Commission) which has used this principle for many years (the Bureau of Reclamation switched to this principle in 1952 - benefits used to be calculated as expected revenues collected). However, it has not used the same interest and tax charges in calculating the cost of the private alternative as it has applied to the cost of Federal power. Since the Government interest rate is lower than the private interest rate, the comparison is biased in favor of public power and overstates benefits. The lower Federal interest rate is partly due to the fact that Government bonds do not reflect the risk involved in power projects.

The objective is to ascertain whether the growth of power output is being accomplished in the most efficient manner, using the least amount of the nation's resources. The alternative cost principle assists in achieving this, for if benefits are limited by the cost of the most likely alternative, a benefit-cost ratio greater than one can only occur if the cost of the project is smaller than the cost of the alternative. The degree to which the benefit-to-cost ratio exceeds unity indicates the relative advantage of the project over its alternative.

The use of alternative cost as a measure of benefit does not imply that all projects with ratios greater than one should be undertaken. In addition, the alternative cost principle is only applied if it is clearly established that the increased amount of power can be sold at the going rate structure.

CONVENTIONAL METHOD

The conventional benefit-to-cost ratio calculated by the Corps of Engineers takes account of total costs throughout the life of a project, i.e. major equipment replacement, maintenance, operation, overhaul, etc. However, in computing the costs of a hydroelectric facility and its most likely alternative for power costs and benefits, actual current prices are used.

Thus, the benefit is equal to the present cost of constructing the alternative additional generating capacity and the cost of producing energy from the alternative plant. This benefit is an annual benefit which is assumed to recur in an equal amount in every year of the economic life of the project. No allowance is made for future changes in real cost or, for that matter, in the reality of technological change whereby the alternative cost becomes smaller. Also, other alternatives based on new technology could become feasible during the life of the hydroelectric project.

Since conventional procedure assumes no change at all, except to remain constant, it could bias the benefits up or down depending on future developments.

LIFE CYCLE METHOD

Life cycle costing varies from the conventional methodology utilized by the Corps in that it requires explicit projection of variable unit costs and operating factors for both the public project and its alternative into the future. While its theoretical rationale is apparent, failure to apply it in the evaluation of hydroelectric projects did not become an important issue until developments in recent years resulted in substantial increases in fuel cost which constitute a major portion of thermal electrical generation costs. Using projected future costs in power value analysis does inject more realism into the process of economic evaluation. It, of course, also introduces assumption and uncertainty.

Life cycle analysis is essentially the same as traditional B/C analysis. The difference lies in the fact that life cycle analysis allows for inflation. Theory holds that allowance must be made in the cost analysis process to account for the decreased purchasing capacity of capital with the passage of time. This decrease in value is what we commonly term inflation. In such studies, a blend of present and future costs is achieved in order to compute a total cost of ownership over time. This process permits comparison between project systems having different variable purchase, maintenance, operation, and replacement costs.

The major variable cost for a thermal plant is for fuel, whose costs, in response to a variety of environmental, safety, economic and marketing forces, have in the past several years risen much more rapidly than the general price level. Furthermore, costs for all three of the major fossil fuels, i.e. coal, natural gas and petroleum, are still in a dynamic phase where they may move either in an upward or a downward direction in the long run. To conduct life cycle analysis, we must develop an analytical basis for projecting changes in the variable costs of hydro plant and thermal alternatives and the cost of replacement plant.

Also, if benefits and costs are to be stated in prices of the period in which each in incurred, then a discount factor that fully compensates for the rate of inflation should be used. Furthermore, to the extent that life cylce analysis includes general inflation in the escalation rates, it is not in accordance with the Water Resource Council's Principles and Standards.

RELATIVE PRICE SHIFT ANALYSIS

A refinement of the life cycle methodology focuses upon relative price shifts (net of general inflation) among various commodities employed in the generation of power. Relative price shift analysis goes beyond a static benefit-to-cost comparison by considering changes in underlying price relationships that might occur over the life of the project. Real price changes, net of general inflation, are used. The use of relative price shifts is discussed in the Water Resources Council "Establishment of Principles and Standards for Planning" (pages 10 and 11).

> "When prices are used in evaluation they should reflect the real exchange values expected to prevail over the period of analysis. For this purpose, relative price relationships and the general level of prices prevailing during the planning study will be assumed to hold generally for the future, except where specific studies and considerations indicate otherwise."

The focus on real price relationships is important. The basic rationale for this approach is as follows: the monetary value of any good is ultimately valued in reference to other goods (goods refer to all things of value - i.e. labor, material goods) available in the market place. If all goods inflated at the same rate, then in effect their value would not be altered. By concentrating on relative price changes, we are considering fundamental changes in the valuation of a single good.

RELATIVE PRICE SHIFT ANALYSIS (Continued)

In the utilization of relative price shift methodology, it is necessary to discount benefit and cost flows at rates which exclude the premium associated with inflationary expectations. Since the relative price shift methodology states benefits and costs in current prices with only real economic value changes considered, then a discount rate containing no inflationary premium is appropriate.

Relative price shift analysis is used in order to fully quantify the benefit resulting from power generation with a renewable resource. The price for any good can change relative to the general level of prices, therefore, in an era of continued inflation the need to focus price shifts among commodities gains in importance. The utilization of relative price shift methodology elicits the economic energy benefit associated with tidal power much more clearly.

RELATIVE PRICE SHIFT ANALYSIS

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This document is Chapter 4 of the report entitled "Tidal Power Study, Cobscook Bay, Maine Preliminary Report on the Economic Analysis of the Project" March 1979. It explains how relative price shift analysis was accomplished for that study as well as how life cycle analysis had been conducted in prior studies.

IV. Relative Price Shift Analysis

A. Introduction

In September of 1976 Governor Longley of Maine requested that the New England Division evaluate Passamaquoddy tidal power on the basis of life cycle cost analysis. The following technical definition explaining life cycle costing has been extracted from the General Provisions of Armed Services Regulation dated 21 May 1976:

> "The life cycle cost of a system or item of equipment is the total cost to the Government of acquisition and ownership of that system or item of equipment over its full life. It includes the cost of development, acquisition, operation, support and where applicable, disposal. Since the cost of operating and supporting the system or equipment over its useful life is substantial and, in many cases, greater than the acquisition cost, it is essential that such costs be considered in development and acquisition decisions in order that proper consideration can be given to those systems or equipment that will result in the lowest life cycle cost to the Government."

The conventional benefit-to-cost ratio calculated by the Corps of Engineers takes account of total costs throughout the life of the project - i.e. maintenance, operation, rehabilitation, in today's prices. Life cycle costing varies from the traditional methodology utilized by the Corps in evaluating water resource projects by projecting unit-cost prices into the future.

B. Preliminary Life Cycle Cost Analysis

In response to the Governor's request the Corps of Engineers performed a preliminary life cycle cost analysis, beginning in late 1976 and extending into 1977, on the 500MW international Passamaquoddy project. The analysis employed a computer model for life cycle cost studies based upon the model described in Chapter VI of the U.S. Department of Commerce, National Technical Information Service Report AD/A-018 dated July 1975, entitled "Hydroelectric Power Potential at Corps of Engineers Projects." The Federal Power Commission (now the Federal Energy Regulatory Commission, FERC) utilizing the model furnished the necessary expertise and analysis.

In applying the computer model the 500 MW international tidal power project was compared to its most probable alternative as determined by the Federal Power Commission, a combined cycle plant. The model allowed escalation rates for five cost variables - operation and maintenance, generating plant, substation, transmission lines, and fuel; to be input. Annual escalation rates of 3, 5, and 7 percent were selected to reflect a range of increases in costs and were applied to each of the five variables. Utilizing this input the information on the escalation of the annual cost of the tidal project and its alternative as a function of time, presented in figures 1, 2, and 3, was derived. These figures are based upon a project life of 100 years for the 500 MW international Passamaquoddy tidal power project and the assumption that the project went on line in June 1976 with annual costs of $121,121,000 and production of 1,932,000,000 kwh/year. For comparison purposes, both the alternative and the tidal power project were assumed to be financed at 6-3/8%.

In escalating power benefits (the alternative's cost) and project costs, the former increase at a more rapid rate, in this analysis. The principal reasons for this are: (1) the change in the depreciation rate of the alternative plant; and (2) the reliance of the alternative upon a fuel which increases in price as it becomes increasingly scarce.

The sharp jumps in the curves (figures 1-3) associated with the alternative project result from the shorter life span of the alternative vis a vis the tidal project. This shorter life results in a change in the fixed depreciation charge needed to cover the initial cost of the thermal project whose cost is increasing by $(1+i)^{30}$ at each replacement, where i is the escalation rate and 30 is the life of the alternative. Due to the escalation in costs assumed to take place every year, the cost of building the combined cycle plant increases with each installation, and therefore the depreciation charge increases.

Figure 4 displays the impact of the various escalation rates upon the benefit to cost ratio of the project, and it is apparent that under the method employed in this study an escalation rate of approximately four percent is required for the project to reach a break-even level over its life time.

Line projections for annual power benefits and costs intersect after a period of project operation and the benefit/cost ratio for that point is 1.0. The following indicates the year of this intersection for each escalation rate:

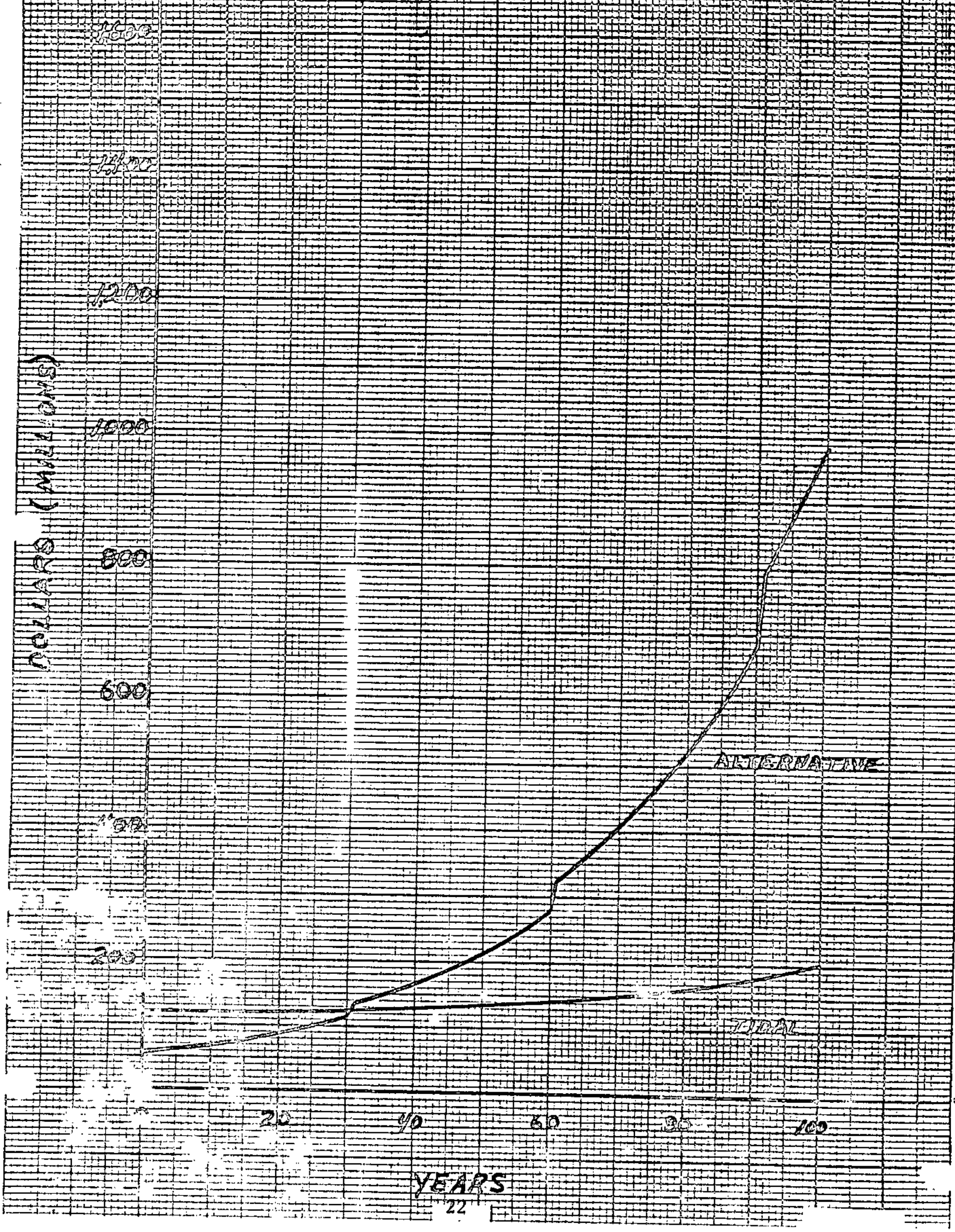
Escalation Rate	Year BCR = 1.0
3%	31
5%	20
7%	15

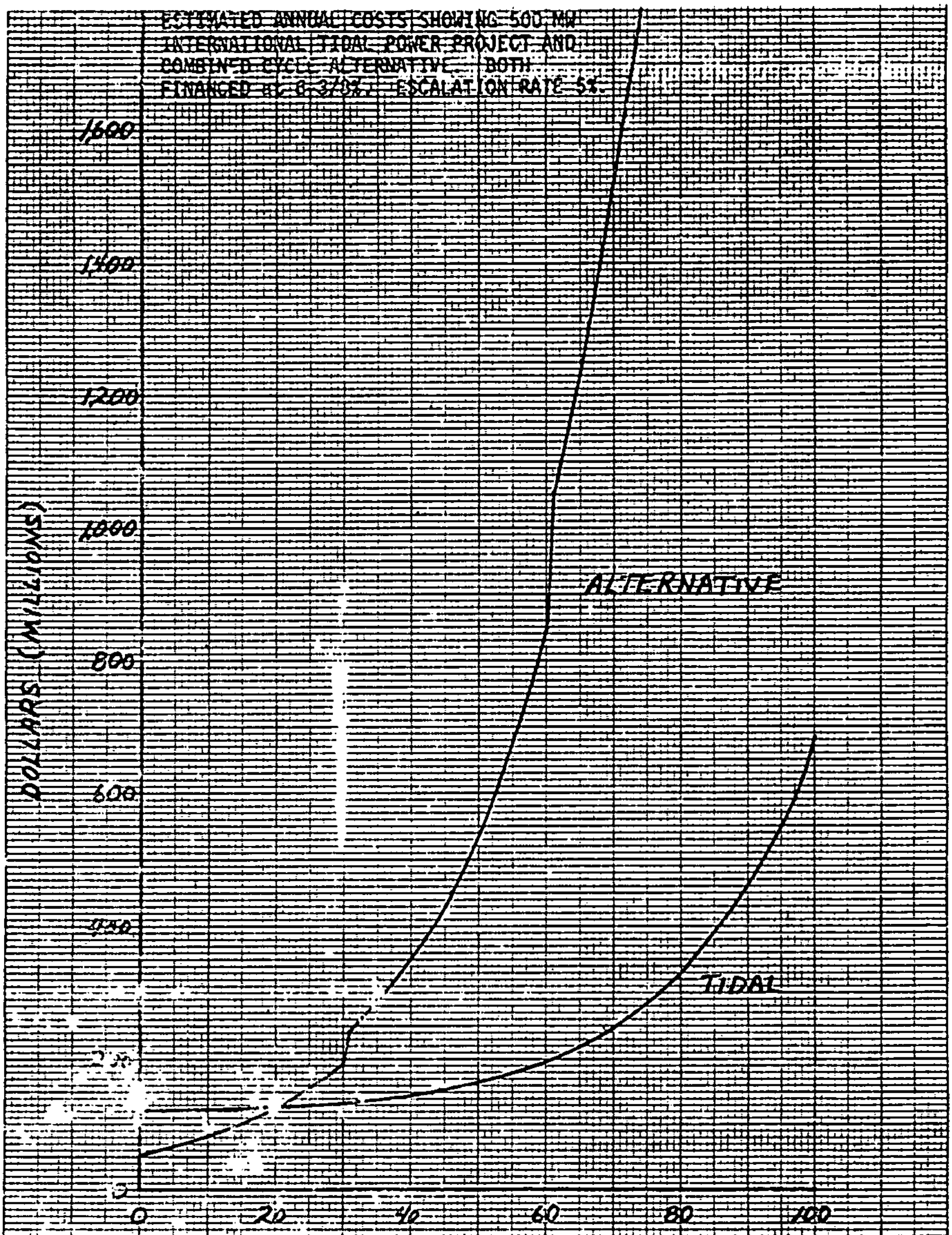
TABLE 1

Life-Cycle Analysis of 500 MW International Tidal Power Project
(Both Plants Financed at 6-3/8%)

Interstate	Escalation Rate	Plant Type	Total Present Worth (6-3/8% Discount Rate)	Annual Cost (Using CRF 100 Yrs. 6-3/8%	Levelized Cost (Mills/KWH)	Life Cycle B/C Ratio (Power Benefits)
6-3/8%	3%	Alternative	$1,491,758,000	$ 95,294,000	49.3	.76
6-3/8%	3%	Tidal	1,958,832,000	125,130,000	64.8	
6-3/8%	5%	Alternative	2,731,104,000	176,463,000	90.3	1.32
6-3/8%	5%	Tidal	2,072,210,000	132,373,000	68.5	
6-3/8%	7%	Alternative	6,531,940,000	417,260,000	216.0	2.70
6-3/8%	7%	Tidal	2,420,867,000	154,645,000	80.0	

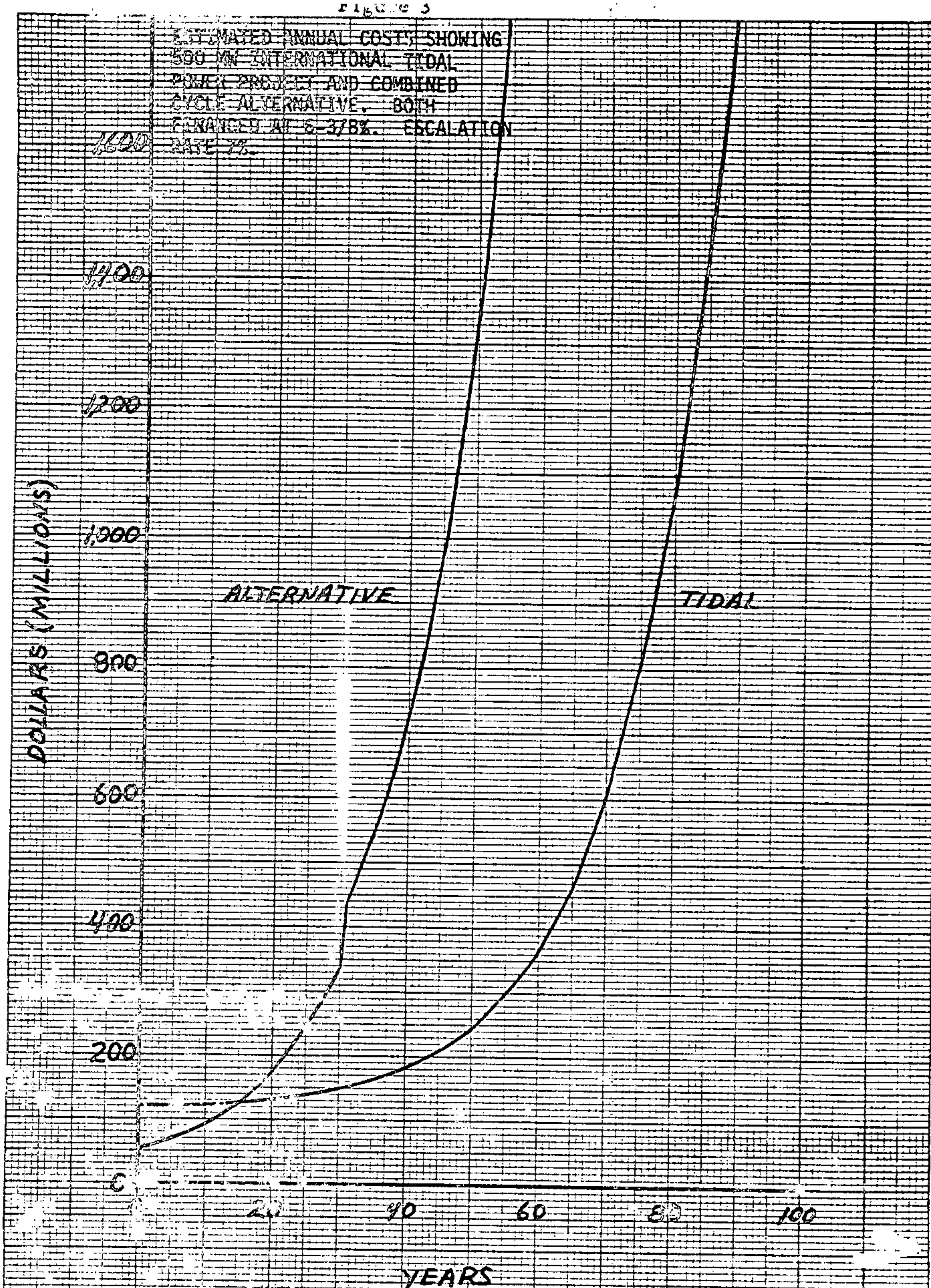
ESTIMATED ANNUAL COSTS SHOWING 500 MW INTERNATIONAL TIDAL POWER PROJECT AND COMBINED CYCLE ALTERNATIVE. BOTH FINANCED AT 6-3/8%. ESCALATION RATE 3%.

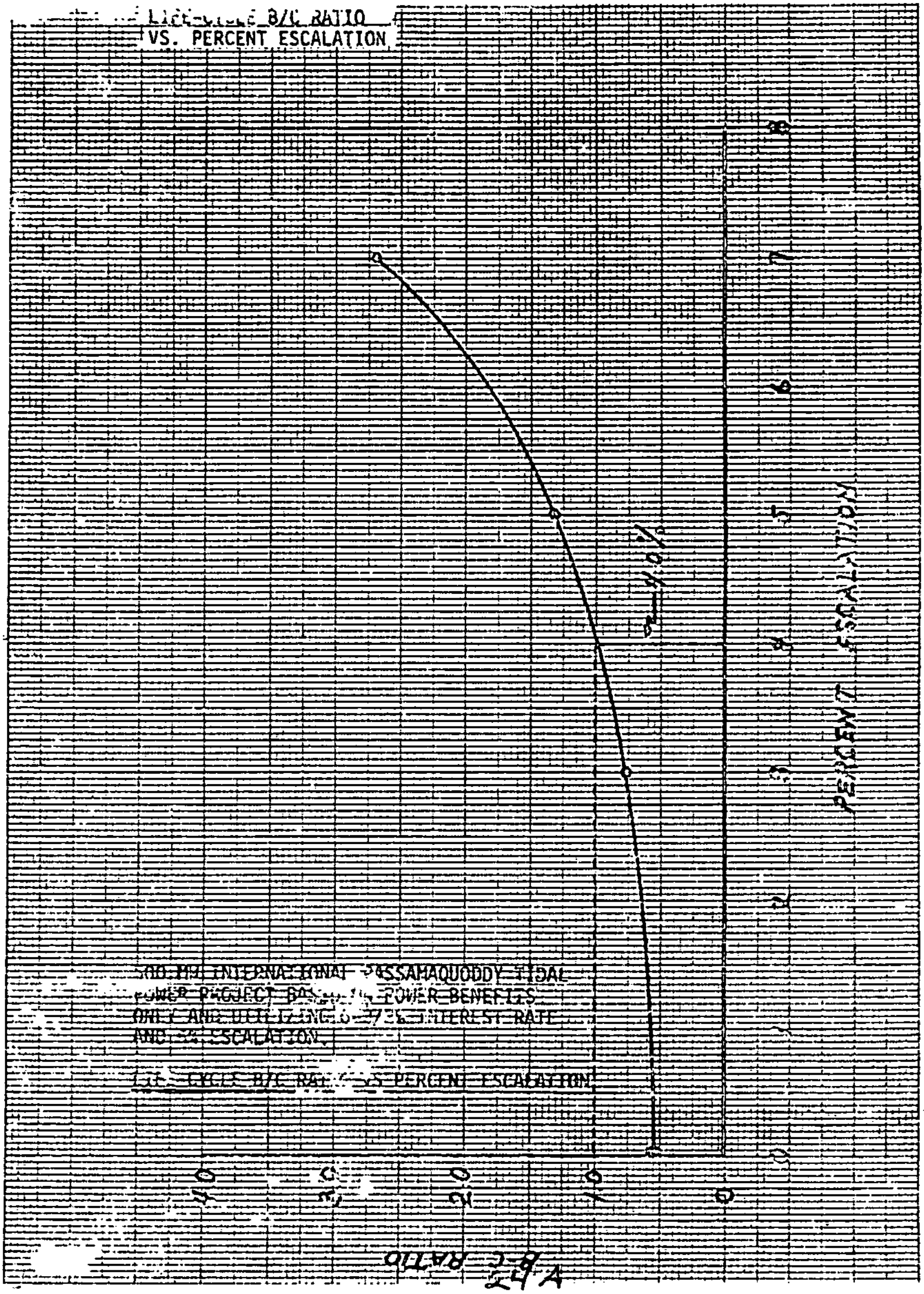




ESTIMATED ANNUAL COSTS SHOWING 500 MW
INTERNATIONAL TIDAL POWER PROJECT AND
COMBINED CYCLE ALTERNATIVE. BOTH
FINANCED AT 8 3/8%. ESCALATION RATE 5%.
DOLLARS (MILLIONS)
1600
1400
1200
1000
800
600
ALTERNATIVE
TIDAL
0
20
40
60
80
100
YEARS

Figure 5


ESTIMATED ANNUAL COSTS SHOWING
500 MW INTERNATIONAL TIDAL
POWER PROJECT AND COMBINED
CYCLE ALTERNATIVE. BOTH
FINANCED AT 6-3/8%. ESCALATION
RATE 7%.
1600
1400
1200
1,000
800
600
400
200
0
DOLLARS (MILLIONS)
ALTERNATIVE
TIDAL
20
40
60
80
100
YEARS


VS. PERCENT ESCALATION
PERCENT ESCALATION
B-C RATIO
0
1.0
2.0
4.0
0
1
2
3
4
5
6
7
8
POWER BENEFITS
INTEREST RATE
ESCALATION
PERCENT ESCALATION

After the intersection point the project begins to accrue net benefits, but as indicated by the benefit to cost ratio for an escalation rate of 3 percent in table 1, these net benefits may not compensate for the net losses experienced prior to the intersection point.

On the basis of this preliminary report, submitted to OCE in 1978, NED was authorized to proceed with the Plan of Study while revising the initial life cycle cost analysis. In particular, the use of escalation factors including general inflation and applied across all project features, as was done in the preliminary life cycle analysis, was found not to be in accordance with existing regulations and needed refinement. The authorizing document pointed out that while the inclusion of general inflation is not valid in economic analysis under the Principles and Guidelines set by the Water Resources Council, the use of relative price changes is. The reasoning behind this will be discussed in the following section.

C. Relative Price Shift Analysis

Methodology.

Relative price shift analysis goes beyond a static benefit to cost comparison by considering changes in underlying (real) price relationships that might occur over the life of the project. (The term 'relative price shift' will be used in place of 'life cycle costing' throughout this report. This term is felt to be more descriptive of the analysis performed.) The use of relative price shifts is discussed in the Water Resources Council "Establishment of Principles and Standards for Planning" (pages 10 and 11):

> "When prices are used in evaluation they should reflect the real exchange values expected to prevail over the period of analysis. For this purpose, relative price relationships and the general level of prices prevailing during the planning study will be assumed to hold generally for the future, except where specific studies and considerations indicate otherwise."

The focus on real price relationships, net of general inflation, is important. The basic rationale for this approach is as follows: the monetary value of any good is ultimately valued in reference to other goods (goods refer to all things of value - i.e. labor, material goods) available in the market place. If all goods inflated at the same rate, then in effect their value would not be altered. By concentrating on relative price changes, we are considering fundamental changes in the valuation of that good. (In reality, however, inflation is not so evenhanded, since many things, i.e. fixed pensions, debts, are not altered by inflation. Thus, there is always some distortion involved in the valuation of certain goods.)

a. Discount Rate

In the utilization of relative price shift methodology it is necessary to discount benefit and cost flows at rates which exclude the premium associated with inflationary expectations. Charles W. Howe in his book for the Water Resource Monograph Series entitled "Benefit-Cost Analysis for Water System Planning" discusses this rather complex problem in a very easy to understand way:

"Consider a project having an initial construction cost of C_0 and a sequence of annual benefits and costs of B_1; C_1; B_2, C_2; ...; B_n, C_n. Let us suppose that these benefits and costs have been computed in terms of construction period prices. Let i be the discount rate that would be applicable in the face of steady prices. Then the present value of net benefits is given by

$$PVNB = -C_0 + \frac{(B_1 - C_1)}{(1 + i)} + \frac{(B_2 - C_2)}{(1 + i)^2} + \ldots + \frac{(B_n - C_n)}{(1 + i)^n} \qquad (A1)$$

Now suppose that a rate of general inflation of i per year exists. Two things will happen: (1) the B_n and C_n values will increase over time above the values given in equation A1, and (2) the discount rate is likely to incorporate an inflationary premium (i.e., interest rates will increase to protect lenders from a loss of purchasing power on the funds they lend). The latter will certainly occur if the discount rate is derived from the market rates of interest. Let this discount rate be designated r. Then the present value of net benefits as calculated becomes

$$PV = -C_0 + \frac{(B_1 - C_1)(1 + i)}{(1 + r)} + \ldots + \frac{(B_n - C_n)(1 + i)^n}{(1 + r)^n} \qquad (A2)$$

Since the inflationary premium in the discount rate is such that $(1 + r) = (1 + i)(1 + i)$ when the market rates of interest fully compensate for inflation, equation A2 can be rewritten as

$$PV = -C_0 + \frac{(B_1 - C_1)(1 + i)}{(1 + i)(1 + i)} + \ldots + \frac{(B_n - C_n)(1 + i)^n}{(1 + i)^n(1 + i)^n} \qquad (A3)$$

Clearly, the inflationary terms cancel out, and we are left with the same expression as that in equation A1.

Thus we conclude that, in the case of general inflation, it makes no difference whether we use (1) benefits and costs all stated in construction period prices and a discount rate containing no inflationary premium, or (2) benefits and costs in the prices of the period in which each is incurred and a discount factor that fully compensates for the rate of inflation."[1]

Since the relative price shift methodology states benefits and costs in current prices with only real economic value changes considered, Howe's analysis leads to a discount rate containing no inflationary premium as being appropriate for this analysis.

The determination of inflation free discount rates for the privately financed alternative and the Federally financed project is, however, very difficult. This difficulty is complicated by the lack of real understanding as to the exact nature of the Federal discount rate selected by the Water Resources Council.

In general the determination of interest rates[2] should consist of three factors: (1) the risk-free, inflation-free interest rate; (2) the risk premium associated with each entity as an on-going concern (i.e. business and financial risk); and (3) any additional risk premium associated with the construction of a given project (a function of the covariance of the risk between the project and the firm's existing portfolio of projects). It is worth noting that while (1) would be the same for both the government and the private corporation, (2) would be larger for the private corporation, while (3) might be greater for the government depending on the covariance.[3]

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[1]Charles W. Howe, Benefit-Cost Analysis for Water System Planning, Water Resource Monograph Series, no. 2 (Washington, D.C.: American Geophysical Union, 1971), pp. 80-81.

[2]This discussion of the interest rate will be on a very general level. For a thorough discussion of the choice of a discount rate for analysis see:

a. Otto Eckstein. Water Resource Development - The Economics of Project Evaluation. (Cambridge: Harvard University Press, 1958) Chapter IV "The Benefit-Cost Criterion, continued" pgs 81-109.

b. Subcommittee on Evaluation Standards. "Proposed Practices for Economic Analysis of River Basin Projects" pgs. 22-24.

[3]According to Eckstein. " The most important risks of the power program as a whole are that the technology will make the plants obsolete, that economic development will slow down or will take a turn which will not require as much power as anticipated, and finally that serious depressions may reduce the demand" pg. 82.

For the privately financed alternative it can be presumed that the measure of the opportunity cost is similar to the return on the firm's financial instruments. It is generally accepted that the market rates of interest of various securities contain inflationary premiums. By computing the cost of obtaining funds, subtracting the premium associated with inflation, and adding in any additional risk premium associated with the construction of a given project, the appropriate discount rate for this analysis could be determined.

For the government discount rate the process is not as simple. The factors which determine the government rate are not easily verifiable, but the existing rate is either: (1) the rate associated with the government securities in the marketplace, (2) the opportunity cost of capital to government, or (3) the social rate of time preference. The first of these is self evident and easily measureable. The opportunity cost "can only be estimated by tracing the capital to its source and by discovering its value in the use to which it would be put in the absence of the public project. Since the money is actually raised by taxation, the incidence of the marginal taxes necessitated by a project must be assigned to various businesses and households. Specific increases (or forestalled reductions) of taxes must be assumed and assumptions about the incidence of these taxes must be made. Once the tax money is traced to its source, its value in the alternative use can be estimated."[1]

The social rate of time preference is based upon "social policy, as derived from the political process, [which] may prefer [the] rejection of present intertemporal preferences in favor of a redistribution of income towards future generations. . . . It is not logically inconsistent for the same person to be willing to borrow at high interest rates to increase his present consumption while voting to spend tax money to build a project from which future generations will benefit, for in the case of a vote to tax, he can be sure that the other individuals in the society will be compelled to act similarly. Also, the distribution of voting power differs from the distribution of economic power in the market."[2]

The difficulty in determining the inflation free rate, as was discussed in the case of the privately financed alternative, thus becomes much more complex in the case of the Federally financed tidal plant. A cursory analysis by a contractor to NED calculated inflation free discount rates of 11% to 12% for a representative the private utility and 3% to 5% for the Federal Government, the latter being based upon the opportunity cost of capital. These rates are very preliminary and are presented for informational purposes only.

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[1]Eckstein, Otto. Water Resource Development - The Economics of Project Evaluation. pg 97.

[2]IBID. pgs 99-100.

The above discussion of discount rates presented some of the theoretical questions involved in this analysis. However, current policy directives are specific.

The "Principles and Standards" of the Water Resources Council mandates

> "The discount rate will be established in accordance with the concept that the Government's investment decisions are related to the cost of Federal borrowing"

and it is currently set at 6-7/8%. There is no alteration of this rate permitted. This may result in a limited change in the impact of relative price increases upon benefit to cost analysis since benefits and costs will most likely be discounted at rates different from those that would be theoretically valid.

b. Price Shifts

Relative price shift analysis is utilized in order to fully quantify the benefits resulting from power generation with a renewable resource. The price for any good can change relative to the general level of prices. Potential shifts, both negative and positive, can occur in the following project related areas: fossil fuel costs; cost of building the tidal project and the alternative plant; operation and maintenance (O&M) costs; cost of transmission lines and substations, and land costs. Although any price can shift, the direction and amount of any price shift can rarely be determined. Each of the items mentioned above is discussed below, however the base case analysis will focus upon the relative price shifts of the fossil fuel input to the thermal alternative - oil. Other relative price shifts will be examined as a sensitivity analysis.

(1) Fossil Fuels. The fuel costs for the alternative to the proposed tidal project will probably continue to rise more rapidly than the rate of general inflation. This parameter, an important difference between the proposed project and its alternative, is difficult to project due the myriad of variables which need to be considered, ranging from the development of new technologies to the political climate among the Organization of Petroleum Exporting Countries (OPEC).

Long run increases in the relative price of fossil fuels would tend to be dampened by three major factors. One, as the relative prices of existing forms of fossil fuels increase, prices would be reached at which existing technologies - e.g. shale oil recovery, would become economically feasible. In a market economy a substitution effect would occur given that the cross-elasticity of demand is high in the long run for the production of electricity from alternative energy sources and therefore the demand for existing fossil fuels as energy inputs would be transferred to other forms of energy. With demand reduced, given a competitive market economy (this would be approached given a long enough time period), price increases would slow. Two, over time, new technologies for energy production - i.e. fusion power, would become available. These forms of energy, when available, would then become economically feasible at a certain price and would also dampen further price rises among fossil fuels. Three, as the price of energy production rises relative to other goods, the rate of growth in the demand for all energy forms would be reduced below that which would otherwise be experienced. This factor although larger in the long run would remain small overall due to the low price elasticity of demand for energy. The combination of these factors would alleviate some of the upward pressure on prices.

Due to the uncertainties involved in energy price projection and forecasting of the development of alternative energy sources, relative price shifts for fossil fuels are be limited to one lifetime of the thermal alternative - to the year 2023. It is assumed that by this time price increases will be mitigated by technologic developments. Price projections are broken into two time periods: (1) escalation from the present to 1994, when the project comes on line; and (2) from 1994 to 2023, over the first life of the alternative. In addition three rates are utilized for sensitivity reasons - a low rate, a middle and most likely rate, and a high rate.

NED did not perform an in-depth analysis of potential price increases in the rate of fossil fuel at this stage of analysis due to the large number of published studies already available. The studies which were employed for this analysis include: figures generated utilizing the Department of Energy's P.I.E.S. model; a small contract to Meta Systems for a literature search; the Reassessment of Fundy Tidal Power - Reports of the Bay of Fundy Tidal Power Review Board and Managment Committee, November 1977; and a study performed for the Electric Power Research Institute. These studies are not documented in detail but rather their basic results are presented with the reader referenced to the background document for further details.

Historical background to the increase in oil prices recently experienced is given in the Reassessment of Fundy Tidal Power. pgs. 241-243.

> "The world oil market has been subject to major changes in recent years. During the 1960's world production of crude petroleum more than doubled at declining real prices. In 1971, for example, the wellhead price of crude oil in the U.S.A. was slightly below the wellhead

price in 1961, measured in constant dollar values (actual price adjusted for the wholesale price index for industrial commodities). The real market price of crude oil exported by members of the Oil Producing and Exporting Countries (OPEC) declined by nearly 25 per cent over the same period (actual price in dollars adjusted for the price of exports from industrialized countries).

The aggressive market intervention by OPEC in the early 1970's resulted in a tremendous increase in the price of internationally-traded oil. Over the period 1971 to 1974, the job market price of oil exported from OPEC countries increased by 475 per cent in current prices and by more than 300 per cent in prices adjusted for the price of exports from industrialized countries. Prices of crude oil from other sources followed the export prices from OPEC countries with various time lags and by varying, but substantial, rates of increase.

This sudden increase in the price of crude oil, generally considered as the reference price for all energy commodities, reverberated throughout the energy sector. The effects on production and consumption patterns are still not very clear, primarily because it is impossible to separate the effects resulting from this price increase from effects of the serious economic recession experienced by the leading industrial countries in recent years.

The intermediate and long-term outlook with respect to crude oil prices is clouded by uncertainty and is the subject of much speculation. The proven reserves of crude oil as of January 1, 1976 were about 660 billion barrels, of which more than half was located in the Middle East. These reserves are sufficient to cover 34 years of consumption at the level of 1976, but would provide for only 19 years if consumption were to increase annually by 6.2 per cent as it did over the period 1965-1975. However, additional oil reserves will be discovered and the higher prices that now prevail will encourage additional recovery from known reservoirs."

(a) The Department of Energy utilizing the P.I.E.'s model has made some fossil fuel price projections over a short time horizon. DOE projections from 1976 to 1990 are that annual real rates of price increase of 0% and 5% are equally likely. These projections demonstrate the type of impact that an increase in the price of an energy input can have on the demand for that input. Table 3, of the "Executive Data Summary" of DOE's PIES Model Report, entitled United States Total Gross Supply/Consumption of Energy Resources - BTU Growth Rates from 1975 (with natural gas regulation), projects the following annual BTU growth rates for the consumption of oil:

Increase In the Price of Imported Oil (Percent)	Year	Annual BTU Growth Rate (Quadrillions)
Zero (Series C)	1985	3.06
	1990	2.72
Five (Series F)	1985	2.71
	1990	1.98

As the time horizon lengthens and the price increases at a faster rate, demand growth, in this case, is significantly muted.

(b) Meta Systems extracted the sets of projections from cited literature detailed in Table 2.

(c) The Bay of Fundy Tidal Power Review Board and Management Committee concluded:

"Weighing the considerations summarized in the preceding discussion, the following projections were adopted for the purpose of this study.

- Until 1990, the assumed first year of operation of a tidal power project, international crude oil prices, in constant dollars, will remain close to the level of 1975. In other words, it is assumed that producers will be able to adjust prices to "world inflation", as determined by the average price level of products exported from the industrialized countries and obtain an average price in constant dollar values comparable to the price obtained by the main exporting countries in 1975. Actual prices are likely to fluctuate considerably around this average. It is further assumed that the Canadian price will be the same as the world market price. However, even if the Canadian price were kept at a different level, it is appropriate to evaluate alternative modes of generation at world market prices.

Beyond 1990, relative oil prices are assumed to increase by, on the average, 1 per cent per year. For the purpose of sensitivity analysis two alternative assumptions were made. The low price alternative assumes no increase over the planning period and the high price alternative assumes a 2 per cent average annual increase through the planning period."

TABLE 2. PROJECTION OF REAL CRUDE OIL PRICES ($/BARREL) AND RATES OF INCREASE[1]

Year	DRI	M.I.T.	EPRI	Pindyck
1977	11.87	12.00		10.70
78			12.70	10.28
79	(2.7%/yr)			10.19
80				10.26
81	13.18			
82				
83	(3.6%/yr)	(5.5%/yr)	(5.5%/yr)	(1.9%/yr)
84				
85	15.18			11.28
86				
87	(3/6%/yr)			(2.1%/yr)
88				
89				
90	18.16	24.00	23.00-25.00	12.51
95	?	"	"	13.80
2000		"	"	15.18 (2.5%/yr)
2005		"	"	16.72
2010				20.52
2010-		"	"	
25		"		

[1] Data Resources, Inc., "U.S. Long Term Review, Winter 1978," and "Chemical Review".

M.I.T. Workshop on Alternative Energy Strategies, "Energy: Global Prospects 1985-2000," New York, 1977.

Electric Power Research Institute, "Outlook for World Oil Into the 21st Century," New York, May 1978.

Robert S. Pindyck, "Gains to Producers from the Cartelization of Exhaustible Resources," Review of Economics and Statistics, Harvard University, May 1978.

Table 3 details their projections for New England.

TABLE 3

PROJECTED FUEL COSTS
NEW ENGLAND
(June 1976 dollars)

AVERAGE ASSUMPTIONS

	1985	1990	1991-2010*
Residual Oil (0.3% Sulphur)			
$/Million Btu	2.53	2.54	1% annual escalation
$/Blb.	15.00	15.85	1% annual escalation
Distillate Oil			
$/Million Btu	2.89	2.90	1% annual escalation
$/Bbl.	17.00	17.10	1% annaul escalation

*Annual escalation rates are over and above any average inflationary increases as reflected in the Consumer Price Index (CPI)

(d) Foster Associates under contract to the Electric Power Research Institute came to the following conclusions:

"Combining the influences indicated above, foreign oil prices are projected in terms of the generally accepted marker crude, Saudi Arabian light, FOB[1] Saudi Arabia, as set out in Table [4] (in constant 1975 dollars per barrel).

TABLE 4

WORLD CRUDE OIL PRICE PROJECTION

	Base Case	Low Case	High Case	Range of Uncertainty
1976	$11.10	$11.10	$11.10	--
1985	10.00	4.00	15.00	375%
1990	11.00	6.00	17.00	283%
2000	16.75	11.00	22.00	200%

[1]FOB is a shipping term - free on board - basically meaning the cost of product at the source exclusive of freight.

The base case corresponds to about a 10 percent price drop between 1976 and 1985, about a 2 percent per year growth between 1985 and 1990, about 3-1/2 percent per year growth between 1990 and 1995, and about 5 percent growth from 1995 to 2000. . .

The low case in 1985 represents a near total collapse of cartel pricing by OPEC. Even so, the low case price in 1985 would still be well above cost because enough countries like Saudi Arabia, Kuwait and Libya who do not need the current income would unilaterally cut production sharply rather than sell at prices that were much lower than current levels. After 1985, the low case reflects the consequence of new reserves (and/or alternates) being at a much lower cost than anticipated.

The high case price in 1985 reflects what might happen if OPEC ignored the restraints on price previously discussed. The high case prices after 1985 could occur if new reserves (and/or alternates) are at a much higher cost than anticipated. A sustained very high real price of oil such as shown in the high case is quite unlikely, for example, because such a high price in 1985 likely would bring out enough new energy supply, cut demand enough, and/or trigger enough other counter-measures by consumers to bring price down again. . .

The above forecast, of course, assumes that essentially a single price structure will continue in the foreign area in each of the three cases."[1]

The range of the uncertainty given in the previous table is informative in considering the level of confidence associated with any given projection.

Based upon the above studies the following annual rates of real oil price escalation are estimated for the purposes of this study.

	1978-1994	1994-2023
Low Rate	1%	1%
Medium Rate	3%	1%
High Rate	5%	1%

The initi[illegible] cost for the alternative, as provided by FERC, is $2.80/million BTU. Utilizing a conversion rate of 5,900,000 BTU/Barrel this would be a cost of $16.52 per barrel.

[1] Electric Power Research Institute. Fuel and Energy Price Forecasts. Prepared by Foster Associates, Inc. EPRI EA-411 Final Report Volume II. March 1977. pgs III 9-11.

(2) Cost of Building the Tidal Project and the Alternative Plant

a. Construction Costs

Two sources of information were relied upon in analyzing this facet of the relative price shift analysis: a preliminary analysis performed by Meta Systems and the Reports of the Bay of Fundy Tidal Power Review Board and Management Committee.

Historically both construction costs and wages have risen at a rate faster than that of general inflation as documented in Table 5. The relative rise in construction costs was largely due to a sharp rise in construction labor costs that exceeded the rise in general labor costs in the late 1960's and early 1970's.[1] Recently construction labor costs have increased more slowly than general labor costs. The measure of the general level of prices employed was the consumer price index published by of the Department of Commerce.

Construction materials have increased sharply in price over the last 10 years. This increase, however, has not been out of line with industrial commodities as a whole. Industrial commodities have, nevertheless, increased at a slightly faster rate than consumer prices.

Deflated construction costs have exhibited the following real rates of change:

0.9 percent for 1950-1970
1.8 percent for 1970-1978

Construction labor cost increases which rose sharply in the late 1960's and early 1970's and were largely responsible for the relative rise of construction costs during that time period are not expected to experience a relative rise during the period through project completion. "The cost of labor . . . is a major element in the cost of construction . . . It is expected that the net result of various factors [productivity increases, fringe benefit increases, etc.] will be that real construction wage costs will not significantly change in the Maritime provinces during the 1980's."[2] This conclusion by Bay of Fundy Tidal Review Board and Managment Committee can be assumed to be valid for the area of the proposed Cobscook Bay Tidal Power Project.

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[1]Meta Systems Inc.

[2]Reassessment of Bay of Fundy Power. pgs. 239-241.

TABLE 5

Deflated Costs

Year	Construction Costs*	Construction Wages	General Wages	Indust. Commod. Prices	Electical Machinery & Equipment	Consumer Prices
50	62.1	1.86	1.44	78.0	68.9	72.1
51	67.7	2.02	1.56	86.1	78.9	77.8
52	69.4	2.13	1.65	84.1	77.8	79.5
53	71.0	2.28	1.74	84.8	80.0	80.1
54	71.0	2.39	1.78	85.0	81.6	80.5
55	72.6	2.45	1.86	86.9	82.9	80.2
56	72.6	2.57	1.95	90.8	89.5	81.4
57	79.8	2.71	2.05	93.3	96.4	84.3
58	80.6	2.82	2.11	93.6	98.4	86.63
59	82.3	2.93	2.19	95.3	99.9	87.3
60	83.1	3.08	2.26	95.3	99.5	88.7
61	83.9	3.20	2.32	94.8	98.2	89.6
62	86.3	3.31	2.39	94.8	96.7	90.6
63	87.9	3.41	2.46	94.7	95.7	91.7
64	90.3	3.55	2.53	95.2	95.1	92.9
65	92.7	3.70	2.61	96.4	95.1	94.5
66	96.0	3.89	2.72	98.5	97.2	97.2
67	100.0	4.11	2.83	100.0	100.0	100.0
68	105.6	4.41	3.01	102.5	101.3	104.2
69	112.5	4.79	3.19	106.0	102.9	109.8
70	120.1	5.24	3.36	110.0	106.4	116.3
71	127.9	5.69	3.57	114.0	109.5	121.3
72	134.9	6.03	3.81	117.9	110.4	125.3
73	147.7	6.37	4.08	125.9	112.4	133.1
74	173.0	6.75	4.41	153.8	125.0	147.7
75	186.4	7.25	4.81	171.5	140.7	161.2
76	193.6	7.70	5.22	182.4	146.7	170.5
77	211.3	8.09	5.67	195.1	154.1	181.5
78	231.	8.60	6.15	210.	164.	194.5

*"A number of cost indices are available, including the American Appraisal Company indices, the Boeckh indices, the Engineering News Record indices, and the EPA indices. We chose to use the Department of Commerce Composite index because it provides an overall index which accounts for productivity changes." Meta Systems Inc.

On the basis of this analysis it is assumed that construction costs will continue to escalate at a rate greater than that of general inflation. This rate will be closer to the long run real increase due to the mitigation in real increases of wages and the lower rate of increase in the cost of energy inputs. Therefore a rate of real price increase of 1.1 percent per year is assumed for the construction cost.

(b) Cost of Electrical Machinery and Equipment

To the extent that the cost of building these plants consists of electrical machinery and equipment, the escalation rate in relative costs may be lower than 1.1 percent. Real electrical machinery and equipment prices grew at the following rates:

-0.2 percent per year for 1950-1970
-1.0 percent per year for 1970-1978

The future trend is assumed to approximate the long run trend. For the purpose of this report a rate of -.25 percent per year is utilized.

(c) To determine escalation rates for the building cost of the project and of the alternative, weights are applied to the escalation rates for the construction cost and electrical machinery and equipment cost and the resulting two terms summed. These weights are defined as the fraction of total unescalated cost that is attributeable to each of these cost categories.

Meta Systems calculated an escalation rate of approximately 1.1% per year for the tidal plant, assuming very little of the cost of the tidal plant consisted of electrical equipment; and a rate of approximately .85% per year for the combined cycle alternative with weighting based upon several telephone conversations with local utilities.

Based upon a cursory analysis by the Corps of the tidal project's cost, it was decided that a large amount of its construction cost was in electrical equipment - approximately 32%. Utilizing this weight the expected escalation rate is estimated to be .67% per year.[1] Further telephone calls regarding the composition of the combined cycle plant yielded a weight for electrical equipment of approximately 43%. With this weight the escalation rate for the alternative would be .52% per year.

Sensitivity tests utilizing price escalation factors for the replacement plant for the alternative, scheduled for thirty years after the initial construction, will not be made due to the potential substitution of energy sources and the difficulty of price projection that far in the future.

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[1] (1.1%)(.68) + (-.25%)(32) = .67%

Therefore, sensitivity tests will be run for this category for both Meta's estimates and the Corps' estimates.

(3) Operation and maintenance costs are assumed to grow in accordance with manufacturing wages, electrical equipment and machinery prices, and industrial commodity prices. Manufacturing wages have grown at a rate of 5.3 percent per year from 1950 to 1978. Relative to the consumer index, they have grown at a rate of about 1.6 percent per year. The rate of relative growth was

1.9 percent per year for 1950-1970
1.1 percent per year for 1970-1978

Weighting the equipment and industrial commodities indices equally, their rate of relative growth was -0.2 percent per year from 1950 to 1978 and

-0.5 percent per year for 1950-1970
0.4 percent per year for 1970-1978

Assuming that the relative rate of growth of these costs will be 0.0 percent and that relative labor costs will grow at 1.2 percent to 1.4 percent per year; then relative O&M costs will grow about 0.5 percent to 0.8 percent per year.

Furthermore, assuming increases in productivity will occur similar to other industries, then O & M costs will probably not grow relative to the general price level. In fact, they may decline. Thus the estimate for O & M costs is a rate of increase between -0.5 percent and 0.0 percent per year. For this study a rate of -0.25 percent per year is used for sensitivity analysis.

(4) Cost of Transmission Lines and Substations.

In line with the discussion of item 2 above the rate of real price escalation for transmission lines and substations is expected to be lower than 1.1 percent per year. For this analysis a rate of .43 percent per year is utilized for sensitivity analysis based upon a 50% weighting of both construction costs and electrical equipment and machinery.

(5) Land Costs. Since land is fixed in quantity, it should rise in value faster than general inflation, and historically this has been the case. However, increases in land value are not uniform; large rates of increase are experienced in metropolitan areas or highly productive agricultural areas, with smaller rates of increase in other areas. Land values can therefore not be projected with a great degree of credibility. This uncertainty of projection, in

addition to the relatively small proportion of land costs to total construction costs, serves as the basis for excluding land values from the analysis.

Consideration was given to tracing the impact of a relative increase in fuel prices upon construction costs, maintenance materials, interim major replacements and other project and alternative related input; using input-output coefficients. This would provide for a complete consideration of the impact of escalating fuel prices upon the project's economics. This was rejected, however, for the following reasons: (1) it is difficult to determine whether the same ratio of factor inputs to total inputs will exist throughout the economy over time; (2) there is lack of knowledge concerning product substitution possibilities; and (3) there is a lack of authoritative projections for such alternative products.

On the basis of the above discussion, the following analysis will focus on the increase in the relative prices of the fossil fuel input to the thermal alternatives power production cost. Several sensitivity tests will be run analyzing different rates of price escalation factors for various project cost and benefit categories.

Power Value of Tidal Power

The methodology utilized to develop power values for tidal power is based upon the Federal Power Commission's manual Hydroelectric Power Evaluation FPC P-35. This methodology has been incorporated into a "life cycle costing" model by the Federal Energy Regulatory Commission (FERC, formerly FPC) and will be detailed in their forthcoming revised Hydroelectric Power Evaluation. The computation of power values is the same for both hydroelectric and tidal power. The following is taken from the final draft of the above. Specifically, Chapter 5 entitled "Computer Model for Determining Power Value of Hydroelectric Power".

"The annual value of hydroelectric power consists of (1) a capacity value, which is developed from the fixed elements of the cost of power supply from an alternative electric generating plant; and (2) an energy value, which is developed from the variable elements of the cost of power supply from the alternative plant. Within these two basic components there are the following four types of costs that enter into the power value determination:

a. Costs of electric power delivered to the bus bar. (The bus bar is the transfer point between the generating station and the sending substation.) These include generating facility investment costs and the operating and maintenance expenses required to produce power.

b. Investment and operating costs, including the value of energy losses, of sending substation facilities needed to transform bus bar voltage to transmission voltage.

c. Investment and operating costs, including the value of line losses, of transmission required to transmit the electric power to market.

d. Costs of the at-market substation facilities required to convert the energy from transmission system voltage to that most appropriate for delivery to the market. These include facility investment costs, operating costs and substation losses.

A computer program has been developed for assimilating these costs and calculating the capacity and energy value of proposed hydro-electric projects. In this model, investment and operating costs are used to develop annual capacity and energy values at various points for any given number of years up to 100 years. The model also permits the use of time varying cost factors and the application of present worth arithmetic, thereby providing for basic life cycle cost analysis or variable sensitivity analyses over the life of a hydroelectric project.

In studies involving life cycle analysis the program varies those variable cost elements based on an annual fixed rate of escalation,[1] then through the application of present worth and capital recovery factor formula determines the annual levelized costs of these elements. The program, in general, is in an initial phase of development. Future modification is expected to include at least the introduction of supplementary production costing programs to refine energy value evaluation, and additional inputs to refine the life cycle analysis capability."

Table A-1 displays general input parameters. (Tables prefixed by A are located in the Appendix) Tables A-2 and A-3 display sample tidal and thermal input data, respectively, utilized in the program operation.

Escalation rates enter into the computer model via the generalized term

$$\text{PRICE} = \text{initial cost} \times (1 + \text{annual escalation rate})^n$$

PRICE = Escalated fuel cost

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[1]This was modified for this study to permit the input of a rates each year during the 100 year economic evaluation period.

This will update the costs associated with the fuel input of the alternative, while the initial fuel cost data to be input into the program will be updated to 1994 relative price levels by hand. Thus, the computation of the power value of the tidal power plant at low tension connection at market will incorporate all the escalation factors. This point of the computer printout is utilized to maintain comparability with FERC power values. For sensitivity analyses the cost side-plant construction costs, operation and maintenance costs, and transmission and substation costs will be escalated by hand over the relevant period and capitalized to determine an escalated annual cost. On the benefit side, those costs of the alternative impacted will be escalated by hand and then input into the program.

Analysis.

As discussed in the methodology section of this report, this analysis is based upon relative price shifts of oil. In addition, two sensitivity analyses are performed: (1) relative price shifts among other factors - project construction costs, alternative construction costs, transmission line and related structure costs, and operation and maintenance costs; are examined; and (2) relative price increases of oil over the period 1994-2023 of greater than 1% are examined to see at what level a benefit to cost ratio greater than unity would be obtained.

a. Base Case

This case analyzes the impact of relative price shifts of fuel upon project economics. The following rates are utilized:

	1978-1994	1994-2023
Low Rate	1%	1%
Medium Rate	3%	1%
High Rate	5%	1%

Tables 6-8 detail the results of this analysis.

TABLE 6
Power Values[1] - 40% Plant Factor
(mills/kwh)

Fuel Escalation Rate	
1%	35.4
3%	45.7
5%	59.3

TABLE 7
Representative Benefit to Cost Ratios[2]

	Fuel Escalation Rates		
Project	1%	3%	5%
160 Dudley	.52	.67	.87
135 Cable	.56	.72	.93
140 Cooper	.56	.73	.94
110 Birch	.56	.72	.93
135 Goose	.56	.72	.94

A third statistic which is of relevance in relative price shift analysis is the break-even year. This is the year after project construction that the escalating power value equals or exceeds the cost of power generation from the tidal alternative. After this point the project begins to pay for itself.

TABLE 8
Number of Years to Break-Even Point

	Break-Even Value (mills/kwh)	Fuel Escalation Rates		
Project		1%	3%	5%
160 Dudley	68.0	-	-	26
135 Cable	63.7	-	-	19
140 Cooper	63.1	-	-	18
110 Birch	63.6	-	-	19
135 Goose	63.2	-	-	18

[1]The power value FERC calculated for a 125 MW tidal project with a plant factor of .31 was 31 mills/kwh. Their calculations do not consider price shifts. To ensure the consistency of benefit to cost comparisons, the computer model was calibrated utilizing a fuel escalation rate of 0%. In this case the computer calculated a power value of 30.64 mills/kwh. The basic values are in close agreement and therefore comparisons between standard benefit to cost ratios and those calculated herein can be made with relative confidence.

[2]These projects have the best standard benefit to cost ratios.

These tables indicate that while at the high fuel escalation rate the project's power cost will be lower than the alternatives at some point in the future; over the 100 year period beginning in 1994 the initial higher cost of the project's power is not compensated for by future, more heavily discounted, savings.

b. Sensitivity Analyses

The sensitivity analyses utilize the 140 MW Cooper project since it showed one of the highest benefit to cost ratios under both the standard and the relative price shift methods. The following alternative assumptions are made for each facet of cost studied with the resulting benefit to cost ratios presented in Table 9.

Annual Escalation Rate-Plant

	Corps	Meta
Tidal Plant	.67%	1.1%
Alternative Plant	.52%	.85%

Annual Escalation Rate-Operation and Maintenance

-.25%

Annual Escalation Rate- Transmission Line and Associated Costs

.43%

TABLE 9
Benefit to Cost Ratios
Sensitivity Analyses - 140 MW Cooper
Fuel Escalation Rate - 3%

	O + M 0%		O + M -.25%	
Transmission Line and associated Cost	0%	.43%	0%	.43%
Plant				
0%	.73	.72	.72	.72
Corps	.68	.67	.68	.67
Meta	.63	.63	.63	.63

The limited sensitivity exhibited under the scenarios - excepting plant cost, should not be surprising and should be interpreted with exceeding caution. The sensitivity evident is a result of the methodology for computing benefits and cost. Changes in plant cost, transmission line and associated structure costs, and fixed portion of operation and maintenance costs would impact the power value of tidal generation on the capacity side of the benefit ledger. But, since the tidal project analyzed does not have a dependable capacity credit presently, benefits do not rise. Thus for an escalation rate applied to fixed charges the cost of the tidal plant would rise, but the cost of the thermal alternative while rising would not be reflected in project economics.

In addition, the limited impact can be traced to the very low rates of escalation applied over short time periods. - i.e. $a(1 + .005)^{15} = 1.08a$, an increase of .5% for 15 years adds only 8% to the cost of the project facet.

An additional sensitivity analysis utilizes the following future relative price escalation rate for oil to determine a rate at which the project benefit to cost ratio would exceed unity.

Annual Escalation Rate 1994-2023
2%
3%

TABLE 10
Benefit to Cost Ratios
Sensitivity Analyses - 140 MW Cooper
Alternate Future Fuel Escalation Rates

Fuel Escalation Rate 1994-2023	Fuel Escalation Rate 1979-1994: 1%	3%	5%
1%	.56	.73	.94
2%	.62	.80	1.04
3%	.68	.89	1.16

The following tables display the percentage increase in real terms of the price of oil over the time period 1979-2023 under the various cases examined and the actual price used as an input to the analysis.

TABLE 11

Percentage Increase in Real Oil Prices

	Fuel Escalation Rate		
	1%	3%	5%
To 1994	16.1	55.8	107.9
To 2023			
1%	56.5	110.0	180.2
2%	110.3	182.2	276.5
3%	181.8	278.1	404.6

TABLE 12

Increase in Real Oil Prices ($/Barrel)

	Fuel Escalation Rate[1]		
	1%	3%	5%
To 1994	19.18	25.74	34.35
To 2023			
1%	25.85	34.69	46.29
2%	34.74	46.62	62.20
3%	46.55	62.46	83.36

[1]Base cost $16.52.

While the 5%-2% and 5%-3% cases examined in Table 10 are presumed to be extremely unlikely, given the uncertainty associated with the energy sector it is a possibility.

D. Conclusion

The utilization of relative price shift analysis brings out the economic energy benefit associated with tidal power much more clearly. This dynamic economic approach results in the various tidal power project's benefit-to-cost ratios being enhanced. However, with this methodology and assuming relative price shifts for oil along expected levels, tidal power, while eventually providing net benefits during several years in the high escalation rate case, does not provide net benefits over the life of the project. The reasons for this include those which have always weighed against the tidal power concept - i.e. high initial cost and lack of dependable capacity; and the more recent infusion of funds into alternative, and in many cases, less expensive forms of energy. Thus, tidal power, though more competitive today, is still not justified, utilizing the assumptions made herein, on the basis of economic analysis as applied in accordance with the Water Resource Council's Principles and Standards.

GENERAL INPUT PARAMETERS

ESCALATION RATE;O&M=(PU)	0.0000
ESCALATION RATE;GENERATING PLANT=(PU)	0.0000
ESCALATION RATE;SUBSTATION=(PU)	0.0000
ESCALATION RATE;TRANSMISSION LINES=(PU)	0.0000
DISCOUNT RATE;STEAM PLANT=(PU)	.10500
DISCOUNT RATE;HYDRO PLANT=(PU)	.06875
FEDERAL INCOME TX RTE FOR CORP=(PU)	0.000
INVESTMENT TAX CREDIT=(PU)	0.000
BOND INTEREST RATE,THERMAL ALT=(PU)	0.000
BOND DEBT RATIO,THERMAL ALT=(PU)	0.000
BOND INTEREST RATE,HYDRO=(PU)	0.000
BOND DEBT RATIO,HYDRO(PU)	0.000

Table A-2

***** TIDAL POWER INPUT DATA *****

1=SERVICE LIFE OF PLANT=YEARS	100.
2=INITIAL PLANT OPERATION DATE	1987.
3=FINAL PLANT RETIREMENT DATE	2087.
4=ECONOMIC AMORTIZATION PERIOD=YEARS	100.
5=FRACTION OF CAPACITY DEPENDABLE=(PU)	1.00
6=PLANT CAPACITY=KW	125000.
7=INITIAL PLANT FACTOR=(PU)	.00
8=FINAL PLANT FACTOR=(PU)	.00
9=SENDING SUBSTATION OUTPUT VOLTAGE=KV	115.
10=SENDING SUBSTATION CAPACITY LOSS=(%)	.00
11=TRANSMISSION MILEAGE=MILES	123.
12=TRANSMISSION CAPACITY LOSS=(%)	5.00
13=RECEIVING SUBSTATION OUTPUT VOLTAGE=KV	115.
14=RECEIVING SUB. CAPACITY LOSS=(%)	0.00
15=HYDRO ADJUSTMENT FACTOR;CAPACITY=(PU)	0.0000
16=COST OF MONEY=(PU)	.06875
17=INSURANCE RATE;SUBSTATION=(PU)	0.0000
18=FEDERAL TAX RATE=(PU)	0.0000
19=MISCELLANEOUS TAX RATE=(PU)	0.0000
20=LOCAL AND STATE TAX RATE=(PU)	0.0000
21=REPLACEMENT RATE;SUBSTATION=(PU)	.0360
22=REPLACEMENT RATE;TRANSMISSION FACILITIES=(PU)	.0330
23=INSURANCE RATE;TRANSMISSION FACILITIES=(PU)	0.0000
24=TYPE OF TRANSMISSION OH=1 UG=2	1.
25=FACTOR FOR ADM.,GEN.,SUB. AND TRAN.=(PU)	0.00
26=TYPE OF FINANCING PRIVATE=1 PUBLIC=2	2.
27=INITIAL LOAD FACTOR=(PU)	.80
28=FINAL LOAD FACTOR=(PU)	.00
29=SEND. SUB. ANN. O&M COST=$/KW	.32
30=TRANSMISSION LINE ANN. O&M COST=$/KW	1.96
31=REC. SUB. ANN. O&M COST=$/KW	0.00
32=ESTIMATE OF SEND. SUB. INVST.=(DOLLARS)	2000000.
33=ESTIMATE OF REC. SUB. INVST.=(DOLLARS)	0.
34=ESTIMATE OF TRAN. LINE INVST.=(DOLLARS)	8000000.

Table A-3

***** COMBINED-CYCLE INPUT DATA *****

1=SERVICE LIFE OF PLANT=YEARS	30.
2=INITIAL PLANT OPERATION DATE	1987.
3=FINAL PLANT RETIREMENT DATE	2017.
4=AMORTIZATION PERIOD;SUB.&OH TRAN.(WD. POLES)=YEARS	30.
5=AMORTIZATION PERIOD;OH TRAN.(STEEL TOWERS)&UG-TRAN.=YEARS	30.
6=PLANT CAPACITY=KW	600000.
7=INITIAL PLANT NET HEAT RATE=BTU/KWH	9000.
8=FINAL PLANT NET HEAT RATE=BTU/KWH	9000.
9=FUEL TYPE COAL=1 OIL=2 GAS=3 NUCLEAR=4	2.
10=INITIAL PLANT FACTOR=(PU)	.30
11=FINAL PLANT FACTOR=(PU)	.30
12=SENDING SUBSTATION OUTPUT VOLTAGE=KV	345.
13=SEND. SUB. CAPACITY LOSS=(%)	1.00
14=TRANSMISSION MILEAGE=MILES	30.
15=TRANSMISSION CAPACITY LOSS=(%)	2.00
16=RECEIVING SUBSTATION OUTPUT VOLTAGE=KV	345.
17=RECEIVING SUBSTATION CAPACITY LOSS=(%)	0.00
18=FIXED FUEL FACTOR=(PU)	3.00
19=RESERVE FUEL LEVEL=DAYS	90.
20=COST OF MONEY=(PU)	.10500
21=INSURANCE RATE;PLANT AND SUBSTATION=(PU)	.0025
22=FEDERAL TAX RATE=(PU)	.0206
23=MISCELLANEOUS TAX RATE=(PU)	0.0000
24=LOCAL AND STATE TAX RATE=(PU)	.0379
25=REPLACEMENT RATE;PLANT AND SUBSTATION=(PU)	.0035
26=REPLACEMENT RATE;TRANSMISSION FACILITIES=(PU)	.0035
27=INSURANCE RATE;TRANSMISSION FACILITIES=(PU)	.0025
28=FACTOR FOR ADM.&GEN.;SUBSTATION AND TRANSMISSION=(PU)	.32
29=ESTIMATE OF GENERATING PLANT INVESTMENT(DOLLARS)	185000000.
30=ESTIMATE OF SEND. SUBSTATION INVESTMENT(DOLLARS)	5735000.
31=ESTIMATE OF RECE. SUBSTATION INVESTMENT(DOLLARS)	0.
32=ESTIMATE OF TRANSMISSION LINE INVESTMENT(DOLLARS)	9464000.
33=INITIAL COST OF FUEL=DOLLARS PER MBTU	4.36
34=FIXED COST FRACTION FOR O&M=(PU)	.19
35=INITIAL SYSTEM DISPLACED ENERGY COST=MILLS/KWH	31.78
36=DUMMY************************************	0.00
37=ADVALOREM TAX RATIO=(PU)	.99
38=FACTOR FOR ADM.&GEN.;GENERATING PLANT=(PU)	.39
39=INITIAL SPECIFIC HEAT OF FUEL=BTU PER #,GAL.,OR CF	135000.
40=FINAL SPECIFIC HEAT OF FUEL=BTU PER #,GAL.,OR CF	135000.
41=INITIAL LOAD FACTOR=(PU)	.30
42=FINAL LOAD FACTOR=(PU)	.30
43=PLANT ANNUAL O&M COST=$/KW	18.12
44=SENDING SUBSTATION ANNUAL O&M COST=$/KW	.40
45=TRANSMISSION LINE ANNUAL O&M COST=$/KW	.05
46=RECEIVING SUBSTATION ANNUAL O&M COST=$/KW	0.00
47=TYPE OF TRANSMISSION OH=1 UG=2	1.
48=TYPE OF FINANCING PRIVATE=1 PUBLIC=2	1.
49=AVERAGE ANNUAL COST OF NUCLE FUEL INVENTORY=$/KW	0.00
50=ESTIMATED NUCLEAR FUEL-BURN L COSTS=MILLS/KWH	0.00

"Symposium on Relative Price Shift
Economic Analysis as Applied to Public Power Projects"
Sponsored by
Project on Balanced Growth for Maine, University of Maine at Orono
Maine Office of Energy Resources
Maine State Planning Office
U. S. Army Corps of Engineers, New England Division

Center for Research and Advanced Study
University of Southern Maine
Portland, Maine
November 27, 1979

1:00 P.M. Registration

1:30 P.M. Explanation of the purpose of the Symposium - Arthur Johnson, Director, Project on Balanced Growth for Maine

1:35 P.M. Welcome from N.E. Division Engineer, Colonel Max B. Scheider

1:45 P.M. Panel Presentations by:

Philip Hastings, Central Maine Power Co. - "Economic Evaluations of Hydro-Electric Projects Large and Small"

Charles Colgan, State Planning Office - "Relative to What?: Economics of Energy in Cost Benefit Analysis"

Lawrence G. Hines, Dartmouth College - "Criticism of the Present Use of Alternate Cost Approach and Observations about Inclusion of Ancillary Benefits"

William Beardsley, Bangor Hydro-Electric Co. - "A Private perspective on Water Investment Decisions in the Public Sector"

Gerald Dawbin, Maine Office of Energy Resources - "Validity for Assessing Long-Term Capital Investment in Public Power Projects"

Normand Laberge, Half Moon Cove Tidal Power Project - "Life Cycle Cost versus Relative Price Shift Analysis: A Comparative Example"

A. Myrick Freeman III, Bowdoin College - "The Discount Rate in Relative Price Shift Analysis"

William Shipman, Bowdoin College - "Identifying an Appropriate Measure of Benefits for Evaluating Tidal Power in Cobscook Bay"

3:30 P.M. Break

3:45 P.M. Discussion from floor

4:45 P.M. Summary

5:00 P.M. Adjourn

Economic Evaluation
of
Hydroelectric Projects

Large and Small

Prepared for

Symposium on Relative Price Shift
Economic Analysis as applied to
Public Power Projects

November 27, 1979

By

Philip C. Hastings
Research Engineer
Central Maine Power Company

When evaluating hydroelectric projects it is helpful to keep your objective firmly in mind. The objective of power supply planning is to develop an orderly expansion program to satisfy the energy needs of the customer at the lowest cost over the planning horizon, while maintaining adequate reliability and a fair return to investors. The use of relative price shift analysis represents an effort by the Corps of Engineers to more accurately evaluate hydropower projects in an era of substantial price escalation. Economic evaluation of hydroelectric projects should be made over the economic life of the facility to include the effects of inflation, fuel cost escalation, and the time value of money.

Consideration of the process of economic evaluation of power supply alternatives can be separated into three components.

- The accuracy and validity of the assumptions made
- The economic analysis technique selected
- The procedure for applying the technique

This paper will focus on the third component, the procedure for evaluation.

The Power supply planning process begins with a forecast of future customer energy requirements and peak demands. The Central Maine Power forecast consists of separate projections of energy requirements for residential, commercial and industrial customers. The residential forecast is based on an analysis of the electrical consumption of each of the major appliances, including electric space and water heating. The use per appliance is then combined with forecasts of appliances per customer (saturation) and expected number of customers to produce a forecast of total residential electricity needs. The commercial forecast is based on a projection of non-manufacturing employees and energy consumption per employee. The industrial forecast is an extrapolation of recent growth trends. The pulp and paper industry is evaluated in greater depth, due to its contribution to energy requirements. The total energy forecast is then used to calculate expected peak demand based on a projection of system load factor.

The other major data set required for the planning process is the characteristics, such as heat rate, cost, maintenance requirements and forced outage rate, of the various existing generating units in the system, and those that might be added in the future. In general, the various types generation can be grouped into three categories.

- Peaking units, which are used during periods of high demand. These units are characterized by low capital cost and high energy cost, such as gas turbines or diesels.
- Cycling units, which, as the name implies, cycle on during the day to meet load requirements and then effect night when demand is lower. Combined cycle plants or oil-fired units would fall in this category.
- Base Load units operate around the clock, shutting down only for maintenance or repair. These units are typically more expensive to build than the other two categories, but have lower fuel costs. Two examples would be coal and nuclear units.

Hydro is a special category. It typically has a high capital cost, no energy cost, and a limited amount of available energy, which may only be available at certain times.

The generation planner develops a power supply plan using the "mix" of the various unit types which yields the lowest total power production cost to the customer over the planning horizon. The plan must also maintain adequate system reliability, meet environmental requirements, and a host of other constraints. The planning process is not a simple comparison of one type of unit versus another. The objective is to minimize <u>total</u> cost to the customer over <u>time</u>. This may mean for example that a cycling unit would be installed instead of a base load unit because it can be put in service three years sooner, or that the alternative to a large peak hydro unit may not be gas turbines but energy storage plus more extensive use of base load units.

This type of sophisticated planning process requires complex computer programs to efficiently evaluate the large number of possible alternatives. A flow diagram for one such computer program is shown in figure 2. Note the iterative nature of the process and the inclusion of environmental impacts and financial data.

The central point of this description is that economic evaluation of large hydro electric projects should include the impact of the addition on the region's power supply plan over time. All of the potential costs and benefits may not be apparent in a unit-to-unit comparison.

Many groups in New England are currently engaged in a review of existing hydro sites to determine the feasibility of developing/redeveloping their hydroelectric potential. In evaluating these small projects, using the complete planning process described above may not be justified and some simplifying assumptions can be made.

One critical assumption is that the site is small enough that the region's power supply plan will not be measurably changed by the addition. The addition of 3.5 MW of hydro capacity to a 1200 MW system--while it may result in an economic benefit--will not, by itself, measurably change the type or timing of future major additions. This assumption will permit evaluation of the small hydro unit by what I shall refer to as the Displacement Method.

In the displacement method of analysis the small amount of capacity and energy associated with the hydro project are compared to the capacity and energy that would be displaced by the project. See figure 3. This is an economic evaluation of a small hydro expansion recently completed by CMP. The annual fixed cost of the displacement is based on the cost of gas turbine capacity as an alternative diesel generating costs might have been used. If the generating system in question had no additional capacity requirements during the life of the proposed hydro project, then the displaced capacity value would have been zero. The displaced energy cost is valued at system average production cost excluding nuclear. This average value is used since the hydro plant would displace different units at different times throughout the year. The exact value of this displaced energy is highly dependent on the system being studied. Note also that the fuel cost is "levelized". That is, it is a constant annual value which will yield the same present value as the increasing fuel costs over the life of the plant.

In summary, the technique used for economic evaluation of hydroelectric projects is only as good as the accuracy of the assumptions made and the validity of the procedure used.

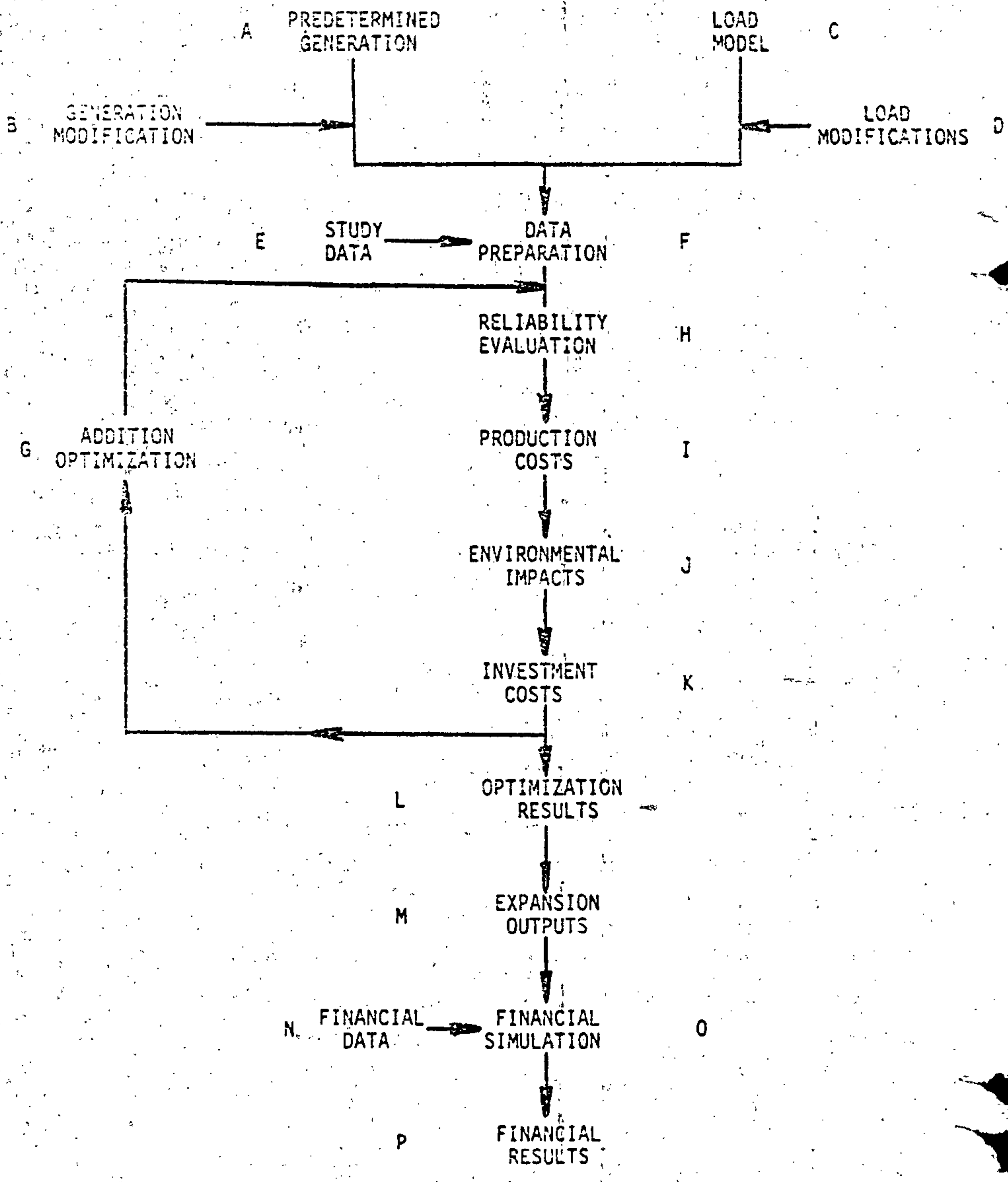

A
PREDETERMINED GENERATION
LOAD MODEL
C
B
GENERATION MODIFICATION
LOAD MODIFICATIONS
D
E
STUDY DATA
DATA PREPARATION
F
RELIABILITY EVALUATION
H
G
ADDITION OPTIMIZATION
PRODUCTION COSTS
I
ENVIRONMENTAL IMPACTS
J
INVESTMENT COSTS
K
L
OPTIMIZATION RESULTS
M
EXPANSION OUTPUTS
N
FINANCIAL DATA
FINANCIAL SIMULATION
O
P
FINANCIAL RESULTS

Figure 2

UNKNOWN IMPACTS

- NEW GENERATION TECHNOLOGIES
- EFFECT OF INFLATION
- MONEY MARKET CONDITIONS
- FUEL AVAILABILITY
- ENVIRONMENTAL CONSTRAINTS
- •
- •
- •

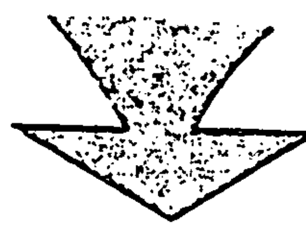
DATA ASSUMPTIONS

GENERATION

LOAD

OPERATIONAL RULES

ECONOMIC FACTORS



GENERATION PLANNING

- HOW MUCH
- WHAT KIND
- TOTAL COST
- FINANCIAL IMPLICATIONS

FIGURE I

SHAWMUT POWER PLANT EXPANSION

ECONOMIC COMPARISON

Hydro	West Side Layout	East Side Layout
Rated Capacity (kW)	3,440	5,000
Average Annual Energy (MWh)	18,000	21,000
Gross Plant Investment ($,000)	4,490	7,060
Investment/Installed kW ($)	1,305	1,412
Annual Cost ($,000)	898	1,412
Annual Energy Cost (Mills/kWh)	49.9	67.2
Fossil Alternative		
Gross Plant Investment ($,000)	798	1,160
Annual Fixed Cost ($,000)	160	232
*Annual Fuel Cost ($,000)	936	1,092
Total Annual Cost ($,000)	1,096	1,324
Comparison		
Annual Savings with Hydro ($,000)	198	(88)
Benefit/Cost Ratio, Hydro to Fossil	1.22	0.94

*Levelized cost over 50 years assuming 6 percent increase per year and a present day fuel cost of is 24 mills per kWh. The levelized fuel cost is 52 mills per kWh over 50 years.

GCP
3-9-79

Figure 3

Rev.
3-21-79

RELATIVE TO WHAT?:

THE ECONOMICS OF ENERGY IN
COST-BENEFIT ANALYSIS

Charles S. Colgan
Senior Planner
Economic Planning and Statistical Services Division
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Paper Presented at Symposium on Relative
Price Shift Analysis

University of Southern Maine
November 27, 1979

The need for comprehensive and effective, energy policies is a major theme of government policy making in the 1970's. But though the need is clear and present, the form and content of such policies is mired in a shapeless morass of technology, ideology, politics, and economics. The search for a Rosetta stone of energy policy to make sense of the many claims for conservation, development, solar power, synfuels, and so on is still woefully absent.

Although I would not pretend to have found that touchstone, the topic of Relative Price Shift Analysis does contain some important concepts not only for the evaluation of specific projects but for the development of more comprehensive analyses which can form the basis for energy policy.

Two key concepts underlie the analysis I propose: First the view that "energy", as we loosely use the term is actually a complex mix of resources which provides the power for our modern, capital (that is energy) intensive economy. The second concept is of a "mix", implying that there is a certain amount of interchangeability among the components of the system.

Historically, the shift from different forms of energy, from animal to steam, to coal, to electrical, to petroleum, nuclear fission, and perhaps ultimately nuclear fusion has been a driving force in the historical periods we have come to refer to as the "industrial revolution", the "electronic revolution", "the atomic age", etc. In both historiography and popular imagination we have viewed our past, present, and to some extent our future in terms of the forms of energy we use.

These shifts of energy sources have largely been determined by interlinked phenomena of technological development and resource availability (or scarcity), both of which are in turn gauged by prices. These long term changes have been characterized by two basic trends:

The change to energy sources which were lower in per unit costs than their competitors.

The change to forms of energy, and energy resources, which are increasingly capable of converting among multiple applications.

Two examples of both these trends lie in electricity, which has in many ways taken over previous forms of both mechanical and thermal energy because it can perform a variety of tasks cheaply and efficiently, and petroleum, which is tremendously coinvertible in its uses and has become the cheapest form of easily convertible energy the world has known.

Petroleum has come to dominate the world energy resource picture because it is a versatile resource: with a little bit of adjustment you can put it in a 2 cubic inch chain saw or a multi-megawatt steam turbine. You can run cars, planes, trains, boats, etc. And until 1973 you could do all that with a price that was steadily declining in real terms. From 1950 to 1972 U.S. real crude prices decreased about 21%.

The United States as a whole, and New England and Maine in particular became increasingly dependent upon oil for a larger share of their energy supplies because of another characteristic of petroleum: its ease of transport from places that have it to places that do not..

As the price of petroleum declined, a number of forms of energy became uneconomic, particularly the small hydroelectric stations which dotted New England's rivers. For example, in East Machias a small hydroelectric station became uneconomical in the 1950's and the station was sold to the town for $1.00. Now there is serious thought being given to reactivating the station since it may once again be economical to do so.

The reason is, of course, that the long downward trend in oil prices has been totally reversed, and replaced with sharp upward trends in prices. Since 1973, the nominal price of oil has more than tripled and the real price more than doubled; and there is every likelihood the nominal price will have more than quadrupled by the end of this year.

The obvious effect of such increases in price is to lower the demand for oil, either through changing the intensity of its use (conservation) or by changing to a different energy resource to perform the same function. But it is insufficient for purposes of public policy simply to identify the fact that demand changes as a function of price rises. Some sense of how and why energy resource shifts occur, and most importantly, how government policies affect those shifts is fundamental to energy policy formulation.

This is true both for the creation of some general energy policies for the nation or the state, but also for the choices of individual projects in which the government becomes involved as prime mover and developer. The need to place specific project choices within some broader context of energy policy has been identified for years as a critical.

There are several major factors which affect the choices among various energy alternatives. Assuming for the moment that market prices will be the major measure of a resource's utility, these factors are:

1. <u>Disequilibria in the economy.</u> The clearest example of this is the administered pricing of OPEC. A second example is

found in the monopoly characteristics of most public utilities which then requires either some form of government price regulation or direct government operation (TVA is an example).

2. The existence of unpriced externalities, particularly environmental impacts and the efficient use of energy resources.

3. The "macro" level variables of aggregate demand in the economy and the disaggregated demands for certain forms of energy. This level can be thought as the planning context for formulation of energy strategies and the choice of energy projects, but as context it is determined independently of specific project or policy evaluation.

In deciding on any kind of energy development project, the government undertakes some form of cost-benefit analysis to determine if the project meets the criterion of minimum rationality, that is that the project yield more in benefits than it takes away in costs. Such cost benefit analyses must meet three criteria in order to provide a full evaluation:

1. They must be technically accurate in their accounting of benefits and costs.

2. They must consider a project in light of the alternatives available for meeting the same goal.

3. They must adequately consider the <u>social</u> costs and benefits of the project.

Of these criteria, I am principally interested in the latter two, since the first is one which can only be evaluated on a case by case basis. The other two criteria have direct bearing on the current problem, however.

The second criterion, that alternatives be evaluated along with the project under consideration is a sticky issue, since the universe of alternatives is always infinite and the time available always incredibly finite. Often the alternatives to be considered are implied in the use of a discount rate based on the opportunity cost of the capital.

But identifying alternatives is at the very heart of "Relative Price Shift Analysis" and some reasonable effort must be made to show that viable alternatives have been identified and analyzed in comparison with the project under consideration.

Since the universe is infinite, some attempt has to be made to narrow the field to the realistically possible alternatives. In order to be considered in a comparative analysis I would suggest two rules of thumb. First, an alternative should be technically comparable to the principal project. A 5 MW hydro plant should not be directly compared with a 2000 MW nuclear power plant. The projects should be of the same scale and capable of performing the same task.

A second rule of thumb would be to compare unknowns with knowns whenever possible. Thus, in the case of most energy projects the alternative would be a petroleum based technology, which is already likely to be a proven use. Since the technologies are well established, the major variable is usually the price of the basic energy resource. It is for these reasons that the comparison of a tidal project with its oil based alternative is entirely appropriate and logical.

However, as logical as this approach is, in fact as necessary as it is to sound cost-benefit analysis, there are still some major issues to be resolved. Principal among these is how best to forecast the future of oil prices in such a way that one can have confidence in the project evaluation which results. The dangers of trying to predict the future of oil prices are obvious. The controlling factor in those prices is an international cartel characterized by shifting and unstable coalitions in pricing decisions. The past behavior of OPEC presents a very uncertain prologue to the future.

Consider that in 1974 OPEC doubled the nominal price of oil from $5.04/bbl to $11.56/bbl, and then in 1975 raised the price again to around $14.50/bbl. It stayed in that vicinity until it took another major jump earlier this year to $18.50/bbl. If estmates of an additional 24% jump in prices by the end of the year are accurate, this would mean a total 356% increase since 1973. The vast majority of that percentage will have come in 1974 and 1979. Certainly this is not a pattern one could extrapolate from with much confidence.

But there are some procedures which can be used to at least get a firm conceptual handle on the possibilities of future oil price increases. The Army Corp of Engineers study of the Cobscook Bay Tidal Power Project contains several approaches, including the PIES model, and the forecasts of Date Resources Inc., and others. However, another indicator of the vagaries of oil price rises is that virtually all of these models significantly underestimate the increase in oil prices which has already occured: The most pessimistic of the various forecasts used in that study do not show a $23.00 barrel of oil until well past 2000, and that is the price which will probably be set by the end of 1979.

How can oil price rises be forecast? One way is to ignore OPEC, and pretend that the price will rise from whatever it is now on the basis of future supply and demand assumptions. Most of the models cited in the Cobscook Bay report use some form of this approach, although they are also somewhat outdated. The Department of Energy has developed what might be termed simple equilibrium projections using a variety of assumptions about the level of world and U.S. demand and supply.

The use of such simple equilibrium models has some powerful advantages. Neither the data nor the theoretical requirements are overly burdensome. Moreover, the long run supply and demand characteristics of the oil market do serve as the background to OPEC pricing policy, which responds to tight supply situations by price increases, and to loose supplies with stable prices. Thus these models might indicate when OPEC were most likely to make large increases in the price.

But there are some potential hazards with such models as well. Primarily, there is the necessity of making assumptions about the future state of the world upon which the projections will be made. This will give the appearance that the cost/benefit analysis is moving away from a concrete, objective evaluation process towards a more "subjective" one. This may have significant implications for the political acceptability of any project so evaluated.

However, I use the term "appearance" of such a move to indicate that the reality is somewhat different. In fact all cost-benefit analyses rest squarely on the strength of their assumptions, most of which are usually only implicit. For instance, most analyses use assumptions of constant prices in calculating the benefit stream.

We must thus inquire about the reasonableness of the assumptions contained in the comparison of alternative energy projects. Is it reasonable to assume a constant real price for oil? Or is it more reasonable to assume, for example, that the price will increase at around 4% a year a likely event according to DOE if world production of oil grows at less than 3% a year while demand grows at a rate greater than 2%

accompanied by comparable figures of U.S. production growing at less than 2% and demand at greater than 0.5%?

I use these numbers because according to the Cobscook Bay study, a price rise of around 4% for oil would tend to yield a Benefit-Cost ration greater than 1. The assumptions are taken from a DOE report to the Congress and represent one of their medium low scenarios.

Even with the necessity of assumptions, it is still possible to do an "objective" analysis. It is both simple and appropriate to perform a sensitivity analysis using various assumptions, as the Corps in fact does do in the Cobscook Bay study. However, there is still a requirement that the point on the possibilities curve where the BCR reaches unity must still be a reasonable one.

Another point of view of the same problem illustrates a test of how reasonable the relationship between a project and its alternative is. Instead of ignoring OPEC, an admittedly unreasonable thing to do, consider OPEC as a random number generator. The generator always produces some number greater than -1 (that is the outcome is always either no change or a price rise). If there is a gap between a projct which is not viable at current prices and one which is at some future price, that gap represents the risk associated with undertaking the project now. If by chance, the price rises more than that amount, the project is a winner. If not it is a loser.

For example, from the Corp's figures, a total rise in the price of oil of around 30% between now and 1990 would make the Cobscook Bay project viable. Thus the Cobscook Bay project is insurance that the price of its electricity will rise no further than electricity generated at a facility using oil 30% above current prices. Or, the price of electricity from

Cobscook Bay will represent a consumer surplus at any price of oil more than 30% above current prices.

Of course OPEC is not purely random.* Based on past OPEC behavior, a 30% price rise over the next 10 years is certainly not unreasonable. Moreover, even the simple equilibrium model projects around a 40% rise in the same period. From this perspective, Cobscook Bay appears to be a viable investment.

The third criterion for a sound cost-benefit analysis is that all externalities be accounted for. A major external cost in energy technologies involves the thermal efficiency of the technology.

The conversion of energy from heat to mechanical energy to electrical energy which takes place in an electric generator inevitably involves some loss of heat. In fact, most power plants can convert only 30% of the BTUs of energy they take in to useful output. This is the major reason that the long run decline in real energy prices has been accompaned by a decline in the efficiency of energy use.

The difference in efficiency of energy utilization among various resources, especially in electrical generation, is primarily due to the unpaid rents of fossil fuels and other fixed supply energy resources. Since the heat produced as a byproduct of electric generation generally commands no price, but does definitely have value because of the scarce, in fact finite, nature of fossil fuels, there is an inherently inefficient use of these resources unless that rent is paid.

It is essential, therefore, that the cost of the wasted heat generated in a thermally based electric generator be counted into the cost benefit analysis. This cost increase with each successive conversion of energy, and with each use of

*It should be noted that in December 1979, two months after this paper was originally presented, the OPEC price of oil rose an additional 30%, to approximately a $28.00/bbl average price.

a fixed resource. Thus the cost will clearly be higher for an oil burning plant, which uses a finite resource and goes through a three stage conversion process (heat to mechanical to electrical) than for a hydroelectric station, which uses only a two stage conversion (mechanical to electrical), with an essentially free energy source (gravity or solar heat).

I will not pretend that the measurement of these rents will be easy, To some extent, it may be argued that the scarcity of oil is already reflected in the OPEC pricing decisions, and that the essentially free energy resource of hydro is already accounted in the cost structures. These arguements have some validity, but it is the fundamental energy efficiency of these technologies which is at issue, rather than the resources themselves. Thus the calculation of inefficiency costs must be done for each alternative under consideration.

Finally, there are the environmental externalities. To a great extent the task of including these in the analysis is easier than for inefficiency externalities. Current environmental laws and regulations generally have the effect of internalizing and pricing the potential environmental damages through requirements for specific control technologies, procedures, etc. What is required here is that the costs of such environmental damage controls must be included ofr all alternatives. This will entail some consideration of the adequacy of these controls as well, and may also require that unpriced externalities be identified and included where possible.

In summary, the relative price shift analysis really should be renamed as relative cost shift analysis, to reflect the full range of economic factors involved in an energy project evaluation. The value of such analysis lies in its explicit consideration of viable alternatives, thus assuring that the best projects will be selected and in that full consideration of issues such as thermal efficiency and environmental effects.

Most importantly, the basic concepts involved in relative costs analysis of specific projects are also the same basic concepts should be applied to the developement of energy policy as a whole. It is obvious, even among the combatants in the energy policy wars that low cost, efficient, and environmentally compjatible energy technologies are the ones which should be identified and undertaken. Granted the evaluation of hydro-electric projects along these lines is alone insufficient to assure an overall sound energy policy. But if both grand strategy and each battle's tactics are fought from the same conceptual basis, surely the war is half won.

A Review of the Determination and Measurement of Benefits in Public Investment Analysis*

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Although early federal public investment projects frequently involved a kind of economic review similar to present-day benefit-cost analysis, the formalization of this analytical technique is usually attributed to the Flood Control Act of 1936. The 1936 Congressional Act instructed the Civil Works division of the U. S. Army Corps of Engineers to identify and include favorable project impacts "to whomsoever they may accrue" as project benefits, which brought about the use of benefit-cost analysis in public investment decision-making and its reliance upon ancillary benefits in the economic justification of federal projects. As one would expect, uncovering ancillary benefits has been a challenge to which the federal agencies have responded enthusiastically and over the years these agencies have identified an impressive number of benefits that accrue to others than the project's

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main beneficiary, such as those protected from floods, and that involve uses other than the main project purpose, such as the use of a resevoir by water skiers.

The ancillary benefit list of public water-resource projects includes stream-flow augmentation for pollution abatement, increased value of land near the project, stimulation of employment when the project is in an economically distressed area, a wide range of recreational opportunities, the value of which has classified and mandated by Congress, downstream power enhancement, as well as other less frequently encountered project impacts. In at least one case -- that of hydro power benefits -- what originated as a ancillary benefit in the case of Army Corps flood control projects and Bureau of Reclamation irrigation projects has become a primary project purpose.

Ancillary benefits have become increasingly important in project justification over the years as earlier public projects have pre-empted the latter investment opportunities with higher b/c ratios. As the better opportunities have been exploited, however, emphasis upon multi-purpose development involving hydro power production has helped offset the decreased return from flood control and irrigation investments. In other words, when a project could not pass the b/c test on the merits of its primary purpose, adding ancillary benefits was a means of raising above unity.

A classic case of project justification relying heavily upon ancillary benefits is the Cross-Florida Barge Canal project. That this federal undertaking was abruptly halted by President Nixon, after it had been more than a century awaiting approval, in no way diminishes its relevance as illustration of what can be achieved in benefit-cost analysis with what may be called aggressive benefit recruitment. During James Monroe's administration in 1824 such a canal was proposed to improve mail service between New Orleans and the East Coast and to protect shipping from West Indies pirates. Later, in 1850, the War Department authorized a survey of a possible canal route, but this was interrupted by the Civil War. Finally, a survey was completed in 1911, and a report which was issued in 1913 found the projected $15,538,000 investment in the canal entirely unjustified on military or commercial grounds.

During World War II, when the Atlantic submarine menace was at its peak, a cross-Florida canal was urged as a means of protecting shipping from the Gulf to the Eest Coast. This led to Congressional authorization of the canal in 1942 -- by a vote margin of one -- and the Army Corps estimated the benefit-cost ratio for the project at 0.18 to 1, a payback of eighteen cents for every dollar invested, certainly one of the lowest benefit cost ratios in recent times. (This is <u>not</u> an 18 percent return on investment; it is a loss of 82 cents on every dollar invested.)

The Cross-Florida Canal was not justified by the Army Corps' feasability study, and the canal was not undertaken during the war. Instead, an oil pipeline across Florida was constructed in less time and at a fraction of the canal's estimated cost. But the World War II Congressional authorization for the canal was not rescinded, and it became the basis for President Kennedy's revival of the project. However, the earlier benefit-cost ratio of 0.18 to 1 was a compelling argument against appropriate federal funds for the project. If the project were to be taken off the Army Corps' shelf, something had to be done.

Fortunately for the Kennedy Administration, the project had been refigured in 1958, and the addition of such ancillary benefits as "recreational boating" and "commercial fishing boat passage," in addition to the more directly related "transportation savings," raised the benefit-cost ratio to 1.05 to 1 -- hardly impressive, but at least not ludicrous. Still, the economic feasibility of the Cross-Florida Barge Canal project was marginal at best and not likely to withstand the competition for appropriations when it was considered by Congress. Moreover, the ratio from bad to worse when it was brought up to date in 1962 employing a discount rate of 2 5/8 percent instead of the earlier 2 1/2 percent rate. The acknowledgement of higher construction costs further depressed the chances of survival. Nevertheless, the project was presented to Congress in the fiscal 1962 budget. It was not funded and a restudy was ordered.

In the restudy, it was rescued by ancillary benefits. Two new benefit categories were added, flood control and waterfront-land value enhancement, and the benefit-cost ratio was refigured for a hundred-year life in addition to the earlier fifty-year life. The result was predictable. The benefit-cost ratio moved upward: to 1.2 to 1 when the project's life was fifty years and to 1.6 to 1 when it was raised to one hundred years. Dredging the canal started March 1, 1964, but somewhat less than eight years and 70 million dollars later, President Nixon brought the project to a halt in 1971, when it was one-third completed. He acted in part in response to mounting public concern for the environment and in part because of a mix-up involving the Council on Environmental Quality. Later court review of Nixon's impoundment of construction funds for the Cross-Florida Barge found that the President without legal authority to terminate an undertaking authorized by Congress, but apparently the Army Corps has decided not to reactivate the undertaking.

There is more to the Cross-Florida Barge Canal case than aggressive ancillary benefit recruitment, however. The barge canal study employs the alternate-cost approach to benefit determination, which has an inherent tendency to inflate the benefit figure above its true market value as used by federal agencies. In the case of the Cross-Florida Barge Canal project, for example, the benefits of barge transportation were in effect equated with the cost of railroad service by deducting the estimated barge rates on the canal from existing railroad rates. Railroad rates are almost without exception higher than barge rates -- since both the costs of providing the two services and the character of the services are different -- which means that such a basis for benefit determination virtually assures a favorable benefit-cost ratio.

But Florida is far from New England and some may question whether such aggressive benefit recruitment and built-in benefit enhancement can happen here. A glance at the Dickey-Lincoln School Lakes project in northern Maine shows two ancillary benefit categories that contribute importantly to the above-unity outcome of that project: downstream benefits and redevelopment benefits. As you all know, the St. John river has a high spring flow and a trickle the rest of the year. Dickey-Lincoln will impound the heavy spring runoff and regularize the river's flow over a longer period, leading to greater output of hydro power at New Brunswick power installations. It is assumed that a portion of that increased New Brunswick output will be sold in the

United States, increasing our power supply. This Canadian power import is figured as a $3,500,000 annual benefit attributable to Dickey-Lincoln. No associated cost for imported power -- marginal or otherwise -- is assessed against the downstream output increase.

Redevelopment benefits are also necessary for a respectable Dickey-Lincoln b/c ratio. With downstream and redevelopment benefits, Dickey-Lincoln achieves a 1.2 to 1 ratio at a discount rate of 6-3/8 percent. Without these ancillary benefits, the project drops to a b/c ratio of 1.1 to 1, an uncomfortably low score particularly at a time when the interest rate stands a 15-1/2 percent in contrast with the project discount rate of 6-3/8. Some may be unfamiliar with the concept of redevelopment benefits, sometimes called simply "development" benefits. In the penultimate draft of the Dickey-Lincoln Environmental Impact Statement, redevelopment benefits were labor expenditures during project construction and project operation and maintenance during the 100-year project life. Note that not only are labor costs during the construction period included, but labor outlays for the 100 years over which the project is presumed to operate are also included. Incidentally, these benefits are not discounted over time. Quite the contrary, they are computed by a formula that results in higher annual redevelopment benefits as the discount rate rises -- $1,691,000 for 3-1/4 percent and

$2,689,000 for 6-3/8 percent. The rationale for including labor costs as a redevelopment benefit is of course that in a distressed economic area such a project makes a net contribution to the economic output of the area. The question that must be asked, however, is whether there are offsetting costs, such as the reduction in opportunities for woods work because of the project's construction and whether the labor force is recruited completely from the distressed area. In any case, the extension of redevelopment benefits throughout the 100-year life of the project appears to be a forecast that is as heroic as it is pessimestic.

The question that can not be ignored is whether the alternate-cost approach to benefit determination is a legitimate basis for economic analysis or merely a strategy for ensuring that benefits exceed costs. Use of a higher-cost transportation alternative, such as railroads, to establish canal benefits is clearly inappropriate, especially since the services are really not the same. The case of hydro power project justification by higher-cost alternatives, such as fossil-fuel power production, is somewhat less clear. Obviously, it is possible that by judicious choice of the fossil-fuel alternative that an above-unity b/c ratio for the hydro project can be virtually assured. For example, the Atomic Industrial Forum found the range of non-hydro kwh costs in 1978 to be 1.5¢ for atomic power, 2.3¢ for coal, 2.5¢ for natural gas, and 4¢ for oil. If the oil alternative is chosen for benefit determination, the b/c ratio of the hydro project is higher than if the atomic power alternative is employed. The defect of the alternate-cost approach is that it makes possible the selection by an agency of other than the lowest-cost alternative. Beyond this, however, the use of the alternate-cost approach in lieu of a marketplace measure can be seriously questioned. Admittedly, regulated utility rates fall short of a free-market benefit measure at times, but to a degree the same problem applies to the use of utility costs as a measure of benefits.

Ancillary benefits pose a somewhat different issue, not so much a question of whether their use in general is legitimate but rather whether particular anciallary benefits are really justified. That is, a public investment project can reasonably be expected to serve a broader purpose than a private undertaking, but this hardly justified the inclusion of benefits mainly to support an otherwise deficient or marginal public project. Finally, if the b/c analysis is to answer the question of whether it is economically desirable to shift resources from the private sector to the public sector of the economy, the public project must demonstrate an efficiency equal to that of private investment. This means, among other things, that relying upon higher-cost alternatives as a measure of benefits and proliferating questionable ancillary benefits turns the project report into an endorsement, albeit ingenious at times, rather than economic analysis.

A Private Perspective on Water Investment Decisions in the Public Sector

BY

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Relative Price Shift Analysis, a refinement in life cycle costing, attempts to internalize into the decision-making process the differential impact of relative price changes in cost and benefit components over time in an inflation-normalized world. It is a sound theoretical technique for both the public and private sectors. The degree to which it can be properly applied in the real world to water investment decisions in the public sector will determine its usefulness. To understand this challenge, it is necessary to consider the theory and then the real world application.

The Theory

No investment decision can be made in isolation. One dollar spent on a tidal project, for example, cannot be spent on insulation or hydropower in a world of limited resources. How our resources are best used is really a matter of relative urgency of the demands placed on them and the relative cost of production. In the field of energy, we must first ask how much energy versus food and/or wilderness, and then we must choose between hydro, wood, oil, nuclear or conservation. In theory our goal is to allocate such that marginal social benefits equals marginal social costs; that is, the cost of the last KWH from a power plant equals its benefit. In a resource-scarce world filled with alternatives, however, our actual goal is to allocate resources to all uses such that the ratio of marginal benefit to marginal costs for all uses are equal. Otherwise, shifting one dollar from energy to paper production or popcorn would make society a little more satisfied.

IN THE REAL WORLD, THE INVISIBLE HAND OF FREE-MARKET FORCES DOES NOT WORK QUITE IN ACCORDANCE WITH THEORY DUE TO WHAT CAN BE CALLED EXTERNAL ECONOMIES OR DISECONOMIES. AN EXTERNAL ECONOMY IS WHERE, AS A BYPRODUCT OF PRODUCTION, A FIRM MIGHT RENDER A SERVICE TO ANOTHER FIRM WITHOUT BEING ABLE TO APPROPRIATE TO ITSELF THE VALUE OF THE SERVICE. ALLAGASH CANOERS, FOR EXAMPLE, INDIRECTLY BENEFIT FROM THE WATER STORAGE AND DISCHARGE POLICIES OF PAPER AND POWER COMPANIES. CONVERSELY, THERE MAY BE EXTERNAL DISECONOMY IN THE USE OF A RESOURCE WHICH IS FREE, SUCH AS WATER, BUT NEVERTHELESS SCARCE. HENCE, INVESTMENT DECISIONS IN THE REAL WORLD ARE DISTORTED BY SUCH IMPERFECTIONS IN THE MARKET PLACE.

AND JUST WHAT IS AN INVESTMENT? CLEARLY IT IS THE ACQUISITION OF A PREVIOUSLY PRODUCED ASSET, SUCH AS ELECTRICITY TO A HOMEOWNER, OR A DAM TO AN ELECTRIC UTILITY. BUT AN INVESTMENT ALSO INCORPORATES TIME, FOR THE COSTS OF PUTTING TOGETHER AND RUNNING AN INVESTMENT INVOLVES COST INPUTS AT DIFFERENT TIMES AND A STREAM OF BENEFITS OUTPUTS AT OTHER TIMES. IN A SIMPLIFIED WORLD, WHAT JOHN SMITH DOES NOT CONSUME, HE INVESTS IN THE FORM OF TAXES, STOCK, ETC. INVESTMENT REFLECTS HIS WILLINGNESS TO PUT OFF CONSUMPTION TEMPORARILY IF THERE IS SOMETHING IN IT FOR HIM - NAMELY INTEREST; THAT IS, THE RETURN ON ONE DOLLAR LENT FOR ONE YEAR. ADEQUATE INTEREST IS DETERMINED BY A RISK PREMIUM FOR DELAY PLUS A PSYCHOLOGICAL PHENOMENON WE CAN CALL TIME PREFERENCE. THE DISCOUNT RATE IS SIMPLY THE VALUE OF A FUTURE DOLLAR IN TODAY'S CONSUMPTION. IN THE REAL WORLD, THE DISCOUNT RATE AND INTEREST RATES MAY DIFFER DUE TO THE IMPERFECTIONS OF THE MARKET, WHILE IN A TRUE FREE-MARKET WORLD THEY WOULD BE THE SAME.

WITH THIS FRAME OF REFERENCE, THE APPLICATION OF RELATIVE PRICE SHIFT ANALYSIS IN THE REAL WORLD CAN BE CONSIDERED.

THE REAL WORLD APPLICATION

FIRST, COMPARISONS OF ALTERNATIVE ENERGY PROJECTS, WHICH DO NOT CONSIDER THE IRREGULAR STREAM OF COSTS AND BENEFITS OVER TIME, CLEARLY FAIL TO MEET THE

TIME CRITERIA OF INVESTMENT THEORY. OIL MIGHT BE CHEAPER THAN TIDAL POWER IN THE FIRST YEAR, BUT NOT OVER THE LIFE OF THE PLANT, HENCE THE VALUE OF LIFE CYCLE COSTING. TO WORK PROPERLY, HOWEVER, LIFE CYCLE COSTING MUST BE BASED ON A SINGLE DISCOUNT RATE FOR THE SIMPLE REASON THAT JOHN SMITH HAS A GIVEN OPPORTUNITY COST ASSOCIATED WITH POSTPONED CONSUMPTION FOR ONE YEAR. TO THE ARGUMENT THAT PUBLIC INVESTMENT IS LESS RISKY AND, HENCE, A LOWER DISCOUNT RATE IS IN ORDER, ONE CAN SIMPLY OBSERVE THAT, IN FACT, THE RISK IS ONLY PERCEIVED TO BE LOWER BECAUSE IT IS SPREAD AMONG MORE PEOPLE. SECONDLY, THE DISCOUNT RATE SHOULD BE RIGHT. AN ARTIFICIALLY LOW PUBLIC DISCOUNT RATE MIS-ALLOCATES RESOURCES BY SHIFTING INVESTMENT TOO FAR INTO CAPITAL-INTENSIVE RENEWABLE ALTERNATIVES. DUE TO FINANCIAL PRESSURE, THE RESIDUAL PRIVATE SECTOR NECESSARILY COUNTERS WITH AN ARTIFICIALLY HIGH DISCOUNT RATE, SHIFTING INVESTMENTS AWAY FROM CAPITAL-INTENSIVE ALTERNATIVES. FOR RELATIVE PRICE SHIFT ANALYSIS TO WORK IT IS NECESSARY TO APPLY A SINGLE, THEORETICALLY SOUND ESTIMATE OF THE REAL DISCOUNT RATE. AN ARBITRARY 6-7/8% DISCOUNT RATE FOR PUBLIC INVESTMENTS AND A MUCH HIGHER PRIVATE RATE DISTORT COMPARISONS. USING EITHER THE PRIVATE OR PUBLIC DISCOUNT RATE FOR ALL ALTERNATIVES MISALLOCATES RESOURCES. THE SOCIAL DISCOUNT RATE FALLS SOMEWHERE IN BETWEEN.

A SECOND POINT IS THAT OPTIMAL RESOURCE ALLOCATION IS REALLY A MATTER OF WELFARE ECONOMICS AND GENERAL EQUILIBRIUM THEORY. TO LIMIT A RESOURCE ALLOCATION ANALYSIS TO A COMPARISON OF, SAY, TIDAL VERSUS COMBINED CYCLE OIL, USING REALTIVE PRICE SHIFT ANALYSIS OR WHATEVER, IS UNSOUND THEORETICALLY. A LITTLE HISTORY BRINGS THIS POINT HOME. IN 1850, 60 PERCENT OF ALL ENERGY IN THE U.S. CAME FROM WOOD AND OUR FORESTS WERE VANISHING, BY 1910 , 60 PERCENT CAME FROM COAL, AND NOW 60 PERCENT COMES FROM GAS AND OIL. EDISON WAS ONLY THREE IN 1850 AND THE FIRST CONTROLLED CHAIN REACTION OCCURRED ONLY FORTY YEARS AGO. TODAY, WE SEE AN EXPONENTIAL GROWTH IN TECHNOLOGY, WITH SOLAR VOLTAICS, BREEDER REACTORS AND EFFICIENT WOOD FURNACES. ENERGY-FREE WINDMILLS DISTRIBUTED

AROUND MAINE CAN SUPPLY POWER AT A SIGNIFICANTLY RELIABLE CAPACITY FACTOR. TO LOCK IN AN ALTERNATIVE, SUCH AS COMBINED CYCLE OIL, FOR 100 YEARS BECAUSE A TIDAL PROJECT IS LOCKED IN FOR THAT PERIOD, SIMPLY DOES NOT MAKE SENSE. IN ADDITION, WHETHER INTENDED OR NOT, FREEZING A TECHNOLOGICAL ALTERNATIVE UNNECESSARILY, AUTOMATICALLY CREATES A BIAS TOWARD A LONG-LIVED OPTION. CONVERSELY, BEYOND A RELATIVELY FEW YEARS INTO THE FUTURE, SAY 30 YEARS, CONFIDENCE WITH WHICH ONE CAN ESTABLISH A RELATIVE SHIFT WEAKENS SIGNIFICANTLY AS ONE COMPLETES A CYCLE OF TECHNOLOGICAL FIXES, AND RELATIVE PRICE SHIFT ANALYSIS BECOMES A REDUNDANCY. IN SHORT, RELATIVE PRICE SHIFT ANALYSIS MAKES MORE SENSE IN THE SHORT RUN THAN IN THE LONG RUN, AND SHOULD BE APPLIED TO AS BROAD A RANGE OF ALTERNATIVES AS POSSIBLE.

A THIRD CONCERN CENTERS ON THE RISK THAT IN OUR PREOCCUPATION WITH CREATING AN EVER MORE REFINED MODEL, WE MAY NEGLECT TO CALIBRATE THE IMPUT. TAKE EXTERNALITIES, FOR EXAMPLE. ONE COULD HYPOTHESIZE THAT INCORPORATED IN THE OIL PRICES IS A PROHIBITION ON OIL DRILLING ON THE GEORGES BANKS. YET THOSE SAME FISH USE PASSAMAQUODDY BAY AS A NUTRIENT-RICH, SAFE NURSERY WHICH WOULD BE COMPROMISED BY A TIDAL PLANT. CONVERSELY, IF JOB CREATION WERE INTERNALIZED AS A BENEFIT, A WOOD-BURNING POWER PLANT MIGHT PROVE THE BEST OPTION FOR POWER IN MAINE, BY FAR. RELATIVE PRICE SHIFT ANALYSIS MUST INTERNALIZE OR EXTERNALIZE THE SAME BENEFITS AND COSTS FOR EACH OPTION AS WELL AS WEIGHING EQUALLY FIXED AND VARIABLE INPUT. FOR EXAMPLE, INTERNALIZING SUCH FIXED EXTERNAL ECONOMIES AS A BRIDGE ACROSS THE DAM WHILE EXTERNALIZING SUCH VARIABLE EXTERNAL ECONOMIES AS JOB CREATION FROM FUEL PRODUCTION, CREATES A DISTORTION TOWARD CAPITAL-INTENSIVE PROJECTS AND VICE VERSA.

TO SUMMARIZE, RELATIVE PRICE SHIFT ANALYSIS SEEMS MOST APPROPRIATE FOR THE SHORT RUN. IT APPEARS THEORETICALLY SOUND IF APPLIED PROPERLY, BUT POTENTIALLY SUFFERS, IN PRACTICE, FROM SUCH ARTIFICIAL CONSTRAINTS AS AN ARBITRARY DISCOUNT RATE, AN INABILITY TO FORECAST PAST A PERIOD OF TECHNOLOGICAL

FIXES, AND A TENDENCY NOT TO STANDARDIZE EXTERNALITIES OR TO CONSIDER A WIDE RANGE OF ALTERNATIVES.

ONE INTERESTING APPLICATION OF THIS TECHNIQUE MIGHT BE A COMPARISON OF SIMILAR CAPITAL INTENSIVE ENERGY FREE HYDRO PWOER PROJECTS IN A SINGLE REGION, SAY THE STATE OF MAINE, WHERE ALL PROJECTS HAVE AN 100-YEAR LIFE AND FOR WHICH A COMMON "SOCIAL" DISCOUNT RATE IS USED. SITES RANGING FROM LARGE AND SMALL TIDAL TO LARGE AND SMALL, EXISTING AND NEW, RIVER HYDRO COULD BE RANKED FOR ENERGY AND BASE LOAD APPLICATIONS. THOSE AT THE TOP OF EACH RANKING COULD THEN BE COMPARED WITH THE APPROPRIATE BEST MIX OF WINDMILLS, NUCLEAR, PUMP STORAGE, COMBINED CYCLE OIL, WOOD, AND CONSERVATION OPTIONS OVER A TECHNOLOGICAL FIX PERIOD OF, SAY, 30 YEARS. SUCH AN ANALYSIS WOULD PRODUCE THE SAME RESULTS FOR BOTH THE PUBLIC AND PRIVATE SECTOR.

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VALIDITY FOR ASSESSING LONG-TERM CAPITAL INVESTMENT IN PUBLIC POWER-PROJECTS

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PAPER PRESENTED AT SYMPOSIUM ON RELATIVE PRICE SHIFT ANALYSIS

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Forecasting the associated costs and benefits of a proposed power project is as fraught with uncertainties as the forecasts of energy consumption or demand, upon which the need for that energy facility is predicated. Each involves assumptions of certain trends and relationships among variables, and most, if not all, of these assumptions are based upon historical experiences and observed behaviors. A common and valid question asked frequently today, however, is "will the future be like the past and, if so, to what degree?" It is my contention in this paper that the future will not be like the past, and that the formerly acceptable assumptions used in evaluating energy facilities, both in the determination of need and in the relative comparisons among various available alternatives, are no longer valid and applicable.

Many advances have been made in modeling capabilities, computer techniques, statistical forecasting methods, and other analytical tools that are essential to energy facility evaluation. Much research has been done on behavioral analyses, econometric relationships, consumer preferences, and the various parameters that determine energy demand growth, the need for power, and consumer responses to energy pricing. The Arab-OPEC oil embargo of 1973-74, continued OPEC oil price increases since that time, heating oil, kerosene and gasoline supply uncertainties of the past year, as well as the current Iranian crisis, have all taught us, or should have taught us, the precariousness of our present energy situation. As a nation, we can no longer afford to depend upon external sources for our energy supplies. Environmental realities of dwindling land resources; the encroachment of civilization on the precious little remaining wilderness areas; air, land, and water pollution problems, as well as difficulties with nuclear safety and radioactive waste disposal, have pressed home the inherent dangers of continuing on our present path of energy development.

Why, then, do we continue to cling to an outmoded and outdated method of economic evaluation of our energy facility projects, the method of "static" economic analyses and overly simplistic cost-benefit analyses that fail to recognize the dynamic nature of our modern economic society, that fail to recognize the new "energy economics" of the post-embargo, environmental awareness era, and that fail to recognize the advances made in statistical and econometric analysis techniques in the last decade?

Why, to press the point a bit further, do Federally-mandated procedures for Federally funded projects fail to recognize the national balance-of-trade deficit that is caused primarily by the purchase of foreign crude oil from Arab-OPEC nations, and is there no procedure by which such externalities can be incorporated into energy facility evaluation with appropriate economic values assigned?

To return to the case at hand, the incorporation of relative price shift analysis into the Cobscook Tidal Project evaluation is, at least, a step in the right direction. This change in evaluation procedures at least partially recognizes one of the factors that I have discussed above, that of the "new energy economics" that was so precipitously thrust upon us in 1973. However, this relative price shift analysis is only a first step to bringing energy facility evaluation methods up to where they need to be to fully consider the ramifications of energy project development.

The Maine Office of Energy Resources has long championed the concept of life cycle costing for energy project evaluation. We have recognized that, as non-renewable resource stocks are depleted, as exploration and recovery costs of the remaining fossil fuel reserves increase at a more rapid rate than the general rate of inflation, and as nuclear power plant costs continue to escalate with more stringent safety requirements and the concomitant construction standards and quality control and quality assurance procedures, a more realistic evaluation method was required for energy projects than the previously accepted "static" analysis procedure that had sufficed through an era of relatively modest (1-3% annually) inflation rates and declining real and relative energy prices. Even given the uncertainties of forecasting the associated relative prices for the various alternative energy developments, the assumption of no relative price shifts is at least as uncertain and, in all probability, much less realistic in view of the 1973-1979 experiences and most credible energy price forecasts. What remains to be done, perhaps, in the relative price shift analysis, is to attach degrees of risk, or uncertainty, to the various price differentials, and to run sensitivity tests on the differential escalation rates so that degrees of exposure to potential uneconomic allocation of resources may be ascertained. Armed with this information, decision makers could then make more informed choices between the alternatives presented.

But, even this method will not provide for "correct" decision making, for we have not yet accounted for the external balance-of-payments or environmental impact factors, and these must, somehow, be incorporated into the evaluation, in a qualitative, if not a quantitative, way.

Are we ready yet to make a decision and/or recommendation on the project? No, we are not, because now we come up against the Water Resource Council's principles and standards which do not specifically permit the use of relative price shift analysis in determining the project's benefit-to-cost ratio, where these standards state "relative price relationships and the general level of prices <u>prevailing during the planning study will be assumed to hold generally for the future</u>, except where specific studies and considerations indicate otherwise." The difficulty here appears to lie in the lack of a guideline by which the appropriate relative price differential escalation rate may be selected as a basis for project evaluation. In this regard, and on this specific project - the Cobscook Bay Tidal Power Project - the Army Corps of Engineers has apparently done all it can do within the framework of its operating mandate. It has evaluated the project in several configurations and at several differential escalation rates, some combinations of which produced BCR's in excess of 1. Now, however, the Corps has no authority to say that the differential escalation rate for oil that produced the 1-to-1 BCR (approx. 4%) is the appropriate rate to select for justification of continuation of the project. It would appear that an appropriate activity for this steering committee would be to come up with proposed guidelines to present to our Congressional delegation whereby the WRC's principles and standards might be appropriately modified to reflect some realistic differential price escalation rate. Congress should be urged to adopt guidelines that reflect current priorities in energy development, viz., reduction of America's dependence on imported foreign petroleum and development of non-polluting, inflation-resistant indigenous energy resources. Relative price shift analysis of long-lived water resource projects is one method of achieving this objective.

Further work remains to be done; however, on such items as FERC's quidelines for evaluating alternatives for the determination of an appropriate benefit stream. Specifically, again in the instant case of Cobscook Bay, it would seem that the appropriate alternatives are neither base-load nuclear power plants nor peaking gas turbines or combined cycle plants. Tidal plants cannot compete economically with the former due to the nuclear advantage of very low energy costs, and they cannot compete with the latter due to the gas turbine's advantage of very low capital costs. The most appropriate comparison, it would seem, would be to evaluate the tidal project on the basis of displaced oil consumption for electric generation, and to make this evaluation with realistic world oil prices. Current world oil prices are already at levels, for example, that the study does not have them reaching until well into the 1990's. The oil prices used in the projections are completely unrealistic and should be updated before any recommendations regarding the future of this project is submitted to Congress.

It is particularly important from the standpoint of the New England region in general, and the State of Maine in particular, that appropriate evaluation criteria be used in analyzing this project. This region is the most dependent on uncertain foreign oil supplies, and pays the highest energy prices, of any region in the country. We are the most sensitive to the instability of our foreign oil supplies, and their ever-increasing prices. It is only appropriate, therefore, that we should take the lead in urging an updating of the procedures and criteria for assessing long-term capital investment in public power projects.

If the Army Corps of Engineers cannot make such a recommendation in its transmittal of the results of this analysis to Congress, then it is encumbent upon the steering committee, and political and business leaders throughout the region, to make this recommendation, and in the strongest possible terms.

LIFE CYCLE COST ANALYSIS VERSUS RELATIVE PRICE SHIFT ANALYIS: A CASE EXAMPLE

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RELATIVE PRICE SHIFT ANALYSIS VERSUS LIFE CYCLE COST ANALYSIS: A CASE EXAMPLE

BY, DR. NORMAND LABERGE

The U.S. Army Corps of Engineers, New England Division, recently released a report which stated that, "Although tidal power appears to be attractive to many, it is still not justified in accordance with the Water Resource Council's guidelines". The report on the Cobscook Bay Tidal Power Project titled, Preliminary Report on the Economic Analysis of the Project, was expected to serve as a prelude to an extensive three to four year investigation of the proposed All-American tidal project. The conclusions reached by the Corps of Engineers might seriously affect the prospects for the construction of a large tidal power project in Cobscook Bay.

The Corps of Engineers report contains some favorable comments that could lead to a different interpretation based on relative price shift analysis if the results are reconsidered in terms of the project's long-term benefits. Some of these points are described below;

- *if the Cobscook Bay Tidal Power Project had been built in 1936, the cost of energy would have been 0.78 ¢/kwh which is quite low when compared to today's production costs from conventional sources*
- *relative price shift analysis which takes into account the net fuel escalation rate referenced to the rate of inflation indicates that various projects could achieve benefit-to-cost ratios approaching unity for their respective years of operation*
- *the fuel cost for the alternative (combined-cycle plant) compared to the proposed tidal project will probably continue to rise more rapidly than the rate of general inflation*

The prediction of future economic trends and the availability of future energy supplies encompasses drastic assumptions which add uncertainty to any form of economics based on life cycle cost analysis or relative price shift analysis. However, historical evidence and the desired transition to a less oil-dependent economy will most likely constitute the necessary drive to uphold the pertinent assumptions into the near-term future (1990-1995).

Relative price shift analysis was performed for the various plant configurations. The results indicated that the economics for tidal power projects progressively improved with time due mainly to the renewable nature of tidal power production; i.e., no fuel cost. The latest Corps of Engineers report contradicts an earlier study prepared by the Stone & Webster Engineering Corporation for the U.S. Energy Research and Development Administration (ERDA, March 1977). The ERDA report using life cycle cost analysis estimated a 15 year break-even period for a

180 mw power plant at Cooper Island for a 7% inflation rate. The inflation rate was assessed uniformly for all cost components and did not include a fuel escalation rate above inflation. Project economics in the Corps' report should have improved the earlier findings for the following reasons; (1) higher power benefits (3.16¢/kwh versus 2.12¢/kwh), (2) longer project life (100 years versus 50 years), (3) reduced project cost for turbines and dams, and (4) the use of escalated fuel cost rates. The Stone and Webster report stated in 1977 that, "In comparing the various electric power generation options available in New England at this time, it is concluded that a tidal power plant in the Quoddy area would be a valuable asset".

The purpose of this paper is to show the relationship between the general rate of inflation and a fuel escalation rate. When analyzing project economics it will be shown that the assumptions used in relative price shift analysis have to include a statement on the presence or absence of inflation. A simplistic model will be used to identify and quantify the differences that are intrinsically involved in life cycle cost analysis and relative price shift analysis. This discussion will not focus on the methodology, but will instead concentrate on related parameters - present value and the benefit-cost ratio - that illustrate the basic differences between the two forms of economic analysis.

The case example used in this paper will be the Goose Point site one of the various tidal power configurations considered by the Corps of Engineers for Cobscook Bay. The proposed Half-Moon Cove project will also be referenced with respect to the demonstration objectives of tidal power development.

Present value of net benefits is a term used to determine the future worth of an investment at the end of a certain time period. Appendix I describes the derivation of an equation used to calculate the present value of net benefits for a tidal project. The important point to note is the fact that net benefits includes two components - an inflation-independent term and an expression related to the rate of inflation. The following calculations will be used to illustrate this difference.

The discount rate used in the expontentially declining function for present value was adopted in accordance with the criteria developed by the Corps of Engineers. The following discount rates were assumed for marmetrates with no inflationary premium;

tidal project: 0.06875
combined cycle: 0.10500

The choice of an appropriate discount rate is critical to the determination of benefits and costs for future time periods.

Table 1 lists the results for the present value calculations determined in accordance with the appropriate formula (see Appendix II). These calculations were performed on the basis of the following information;

1. Cost Estimates, Corps estimates[1] were used for Goose Point and presented in terms of production values; i.e., cent/kwh

2. Benefit Criteria, a combined cycle plant with a total production cost of 3.1¢/kwh was used as a comparable producer. The distribution of production cost was calculated in agreement with an earlier report[2] revised to reflect the following distribution

   - fuel cost (56.9%)
   - fixed charges (39.8%)
   - operation & maintenance (3.3%)

   A heat rate of 9,000 BTU/kwh was used for hypothetical plant. It should be noted that the adjusted fuel cost translates into an equivalent cost of $11.42 per barrel of oil ($5.825(10^6)$ BTU/barrel)

3. Production Data, the Goose Point plant would have an installed capacity of 135 mw and a capacity factor of 0.396. Other benefits are indicated on Table I as footnotes to the present value calculations.

The results clearly point the impact of inflation on the present value of project benefits and costs. As an example for the year 2017, a fuel escalation rate of 1% in addition to a 4% inflation rate would decrease the present value of the combined cycle plant from 0.21¢/kwh (no inflation) to 0.16¢/kwh. Similarly, the value of the tidal project would decrease from 0.78¢/kwh. The difference in the corresponding net benefits is the most important parameter for this discussion. The effect of inflation has decreased the margin and has therefore improved the relative merits of the projects. The differences in project lifetime (i.e., 100 years versus 30 years) is evidenced for the projected benefits for the year 2018. The long term benefits for the longer tidal plant lifetime can be appreciated by this formulation.

The discount rates used for the previous calculations did not contain any inflationary premiums. The correctness of this methodology has been described in Appendix I on the basis of the independence of inflation for the fixed charge costs. The results indicate the importance of stating the inflationary conditions on the calculation of present value and also emphasizes the utilization of the proper discount rate.

The benefit-cost ratio is the other parameter used to differentiate the results of life cycle cost analysis and relative price shift analysis. The equations used for these calculations are depicted in Appendix II. Two cases will be considered in this paper; i.e., pre-construction and post-construction.

The results for this analysis are listed in Table 2 for the same conditions previously assumed. Three different criterias for tidal power value were used for these calculations as described below:

1. Comparative value of combined cycle plant (3.1¢/kwh distributed in accordance with previous assumptions)

2. Oil replacement value of 2.549¢/kwh which translates into an equivalent cost of $16.50 per barrel. Specifications for the plant are once again 9,000 BTU/kwh and $5.825(10^6)$ BTU/barrel

3. *Oil replacement value of 3.1¢/kwh for an equivalent basis of $20.07 per barrel under the same operating conditions.*

The use of the above criterias will be discussed later. However, the results are obviously more favorable if criteria #3 is used. The amount of time required to achieve break-even operations is determined by the occurrence of a benefit-cost ratio greater than unity. For example, break-even operation occurs between the years 2000 and 2010 (approximately 2006) for a 4% inflation rate and a 1% fuel escalation rate if we use criteria #1 for tidal power value.

The benefit-cost ratio should theoretically give the same results for an economic analysis performed either in "current-prices" or "constant-prices". Relative price shift analysis is presumably adapted to present "constant-prices" under steady price or inflationary conditions. However, the assumption of inflation as opposed to steady prices would definitely change the calculation of a benefit-cost ratio if an inflation independent term exists; e.g., fixed charges for post-construction conditions.

The Goose Point project has been used in this paper as a case example to illustrate the effect of inflation rates on two important economic indicators - present value and benefit-cost ratio. Another project which deserves consideration is the Half-Moon Cove site. The comparitive project costs are listed in Table 3. For the case of the Half-Moon Cove project, the corresponding cost parameters are listed below;

C_1 *(operation & maintenance): 0.83¢/kwh*
C_2 *(fixed charges): 4.49¢/kwh*
C_3 *(Major replacement): 0.15¢/kwh*

The production cost totals 5.47¢/kwh which is less than the corresponding 5.70¢/kwh estimate at the Goose Point site.

The Half-Moon Cove project has received federal and State of Maine assistance to conduct an in-depth feasibility study. Besides providing regional power production, the project is also expected to serve demonstration purposes by enhancing the technical and economic potential of tidal power. The concept of an integrated power network connected with a linked basin mode of development offers the potential to effectively harness the tidal forces of Cobscook Bay and the upper Maine coast. The Half-Moon project in addition to the aforementioned benefits will provide employment opportunities, increase the economic potential for aquaculture development, research and develop tidal power, estimate possible environmental consequences, and serve as a potential catalyst for other tidal projects in the area.

Discussion

The simplistic model referenced in the introductory section of this paper is based on a cash flow analysis for the operation of the proposed Goose Point tidal project. Mathermatically, this typical model is expressed by the following equation in the same terminology previously used:

$$C_1 + C_2 + C_3 = B_1 + B_2 + B_3 + \delta \qquad \ldots (1)$$

where, is either a profit or loss component. If we let eqn.(1) represent the prevailing conditions of January 1979, the following equation then applies for the period from 1979 to the date of operation for an assumed inflation rate (I) and fuel escalation rate (F):

$$[\, C_1 + C_2 + C_3 \,](1+I)^t = B_1(1+I+F)^t + B_2(1+I)^t + B_3(1+I)^t + \delta \quad \ldots (2)$$

where, t, is equal to the number of years from 1979. This model neglects to factor in the cash-flow differential introduced by the construction period. However, once the plant is placed into operation the fixed charge components are no longer affected by inflation. If we let N equal the number of years from 1979 to plant operation and t' the number of years after plant operation, the following expression is then used to represent the resulting cash-flow profile:

$$[\, C_1 + \frac{C_2}{(1+I)^{t'}} + C_3 \,](1+I)^{N+t'} = [\, B_1(1+F)^{N+t'} + \frac{B_2}{(1+I)^{t'}} + B_3 \,] \cdot (1+I)^{N+t'} + \delta \quad \ldots (3)$$

where we have assumed that (1+I+F) is equal to (1+I)(1+F). The use of realistic values for I and F determine the appropriateness of this methodology in evaluating future project benefits.

The difference between life cycle cost analysis and relative price shift analysis seems to focus on the fuel escalation rate. This difference is the only significant alteration to the original ERDA life cycle cost analysis as noted in the more recent Corps' study of relative price shift analysis. Present value of net benefits and the benefit-cost ratio are two terms that have been previously discussed in terms of its relationship to the rate of inflation and fuel escalation. The fact that the fixed charge cost is independent of the rate of inflation after the plant is placed into operation has to be properly considered in order to correctly analyze the future benefits and costs of the project. In this case, it has been shown that the general rate of inflation will change the calculations of the benefit-cost ratio and the present value of net benefits.

The use of an appropriate tidal power value is emphasized by the results of the benefit-cost analysis appearing in Table 2. The criteria value of comparative production at the combined cycle plant was derived on the implied assumption that oil is available at $11.42 per barrel. However, it has been shown that based solely on the oil replacement value, the benefit-cost ratios improve siginificantly for oil at $16.50/barrel and $20.07/barrel. The figure of approximately $20.00/barrel was estimated by an earlier study[3] performed by myself with the cooperation of the Bangor Hydro-electric Company for the Half-Moon Cove project. It would seem, that today when small-scale hydro projects are receiving 4 ¢/kwh for their power, that this criteria is at the very least relevant for reliable tidal power production.

Several critical questions have been raised by the Corps' report. However, the most crucial assumption revolves around the use of steady prices; i.e., no inflation. The results presented in the Corps' report implicitly reflect this assumed condition. The use of a moderate 4 %/yr inflation rate dramatically change the results as noted in Tables 1 and 2 for present value and benefit-cost ratio, respectively. The likelihood of continued inflation and fuel cost escalation is highly probable for the near future. In order to develop tidal power, an environmentally safe energy resource, it would seem that the benefits attributed to a demonstration project should place the Half-Moon Cove project at the top of priority list. The time has arrived to actually harness the tidal forces of this region and thereby realize some results from the countless number of studies conducted on proposed tidal projects.

REFERENCES

(1) *Tidal Power Study, Cobscook Bay, Maine, Preliminary Report on the Economic Analysis of the Project, U.S. Army Corps of Engineers, New England Division, March 1979 (updated July 1979)*

(2) *Stone & Webster Engineering Corporation, Final Report on Tidal Power Study for The United States Energy Research and Development Administration, March 1977, Vol. 2*

(3) *Laberge, N.L., Public Utility Integration with Tidal Power Production, prepared for U.S. Department of Energy, Northeast Region, March 1979*

PRESENT VALUE CALCULATIONS
PROJECT: GOOSE POINT

YEAR	TIDAL PLANT (¢/KWH) C_1	$C_2/(1+I)$	C_3	$SUM/(1+D_1)$	COMBINED CYCLE (¢/KWH) $B_1(1+F)$	$B_2/(1+I)$	B_3	$SUM/(1+D_2)$
I=0.00 F=0.01								
1979	.20	5.42	.08	5.70	1.76	1.23	.11	3.10
1980	.20	5.42	.08	5.70	1.78	1.23	.11	3.12
1987	.20	5.42	.08	5.70	1.91	1.23	.11	3.25
1990	.20	5.42	.08	4.67	2.13	1.23	.11	2.57
1995	.20	5.42	.08	3.35	2.24	1.23	.11	1.61
2000	.20	5.42	.08	2.40	2.35	1.23	.11	1.01
2010	.20	5.42	.08	1.24	2.60	1.23	.11	0.40
2017	.20	5.42	.08	0.78	2.78	1.23	.11	0.21
2018	.20	5.42	.08	0.73	2.82	1.23	.11	4.16
I=0.00 F=0.03								
1979	.20	5.42	.08	5.70	1.76	1.23	.11	3.10
1980	.20	5.42	.08	5.70	1.81	1.23	.11	3.15
1987	.20	5.42	.08	5.70	2.23	1.23	.11	3.57
1990	.20	5.42	.08	4.67	2.44	1.23	.11	2.80
1995	.20	5.42	.08	3.35	2.76	1.23	.11	1.84
2000	.20	5.42	.08	2.40	2.91	1.23	.11	1.16
2010	.20	5.42	.08	1.24	3.22	1.23	.11	0.46
2017	.20	5.42	.08	0.78	3.45	1.23	.11	0.24
2018	.20	5.42	.08	0.73	3.48	1.23	.11	4.82
I=0.00 F=0.05								
1979	.20	5.42	.08	5.70	1.76	1.23	.11	3.10
1980	.20	5.42	.08	5.70	1.85	1.23	.11	3.19
1987	.20	5.42	.08	5.70	2.60	1.23	.11	3.94
1990	.20	5.42	.08	4.67	3.01	1.23	.11	3.22
1995	.20	5.42	.08	3.35	3.70	1.23	.11	2.27
2000	.20	5.42	.08	2.40	3.88	1.23	.11	1.43
2010	.20	5.42	.08	1.24	4.29	1.23	.11	0.57
2017	.20	5.42	.08	0.78	4.60	1.23	.11	0.30
2018	.20	5.42	.08	0.73	4.65	1.23	.11	5.99

NOTES:
1. FIRST YEAR OF OPERATION; 1987
2. DISCOUNT RATE – D_1 = 0.06875 (TIDAL)
   D_2 = 0.10500 (COMBINED CYCLE)
3. PROJECT LIFETIME – 100 YR. (TIDAL)
   30 YR. (COMBINED CYCLE)
4. COST ESTIMATES BASED ON CORPS OF ENGINEERS REPORT FOR PREVAILING COST LEVELS OF JANUARY 1979
5. I – INFLATION RATE
   F – FUEL ESCALATION RATE ABOVE INFLATION RATE
6. SEE APPENDIX I FOR METHOD OF CALCULATION

TABLE 1
PAGE 2 OF 2

PRESENT VALUE CALCULATIONS
PROJECT: GOOSE POINT

	TIDAL PLANT (¢/KWH)				COMBINED CYCLE (¢/KWH)			
YEAR	C_1	$C_2/(1+I)$	C_3	$SUM/(1+D_1)$	$B_1(1+F)$	$B_2/(1+I)$	B_3	$SUM/(1+D_2)$
I=0.04 F=0.01								
1979	.20	5.42	.08	5.70	1.76	1.23	.11	3.10
1980	.20	5.42	.08	5.70	1.78	1.23	.11	3.12
1987	.20	5.42	.08	5.70	1.91	1.23	.11	3.25
1990	.20	4.82	.08	4.18	2.13	1.09	.11	2.47
1995	.20	3.96	.08	2.49	2.24	0.90	.11	1.46
2000	.20	3.26	.08	1.49	2.35	0.74	.11	0.87
2010	.20	2.20	.08	0.54	2.60	0.50	.11	0.32
2017	.20	1.67	.08	0.27	2.78	0.38	.11	0.16
2018	.20	1.61	.08	0.24	2.82	1.23	.11	4.16
I=0.04 F=0.03								
1979	.20	5.42	.08	5.70	1.76	1.23	.11	3.10
1980	.20	5.42	.08	5.70	1.81	1.23	.11	3.15
1987	.20	5.42	.08	5.70	2.23	1.23	.11	3.57
1990	.20	4.82	.08	4.18	2.44	1.09	.11	2.70
1995	.20	3.96	.08	2.49	2.76	0.90	.11	1.70
2000	.20	3.26	.08	1.49	2.91	0.74	.11	1.03
2010	.20	2.20	.08	0.54	3.22	0.50	.11	0.38
2017	.20	1.67	.08	0.27	3.45	0.38	.11	0.20
2018	.20	1.61	.08	0.24	3.48	1.23	.11	4.82
I=0.04 F=0.05								
1979	.20	5.42	.08	5.70	1.76	1.23	.11	3.10
1980	.20	5.42	.08	5.70	1.85	1.23	.11	3.19
1987	.20	5.42	.08	5.70	2.60	1.23	.11	3.94
1990	.20	4.82	.08	4.18	3.01	1.09	.11	3.12
1995	.20	3.96	.08	2.49	3.70	0.90	.11	2.12
2000	.20	3.26	.08	1.49	3.88	0.74	.11	1.29
2010	.20	2.20	.08	0.54	4.29	0.50	.11	0.49
2017	.20	1.67	.08	0.27	4.60	0.38	.11	0.25
2018	.20	1.61	.08	0.24	4.65	1.23	.11	5.99

NOTES:

7. INFLATION RATE IS 1 % AFTER 1994 FOR ALL THE CASES CONSIDERED
8. DEFINITIONS INDICATED BELOW:
   - C_1 - COST OF OPERATION & MAINTENANCE
   - C_2 - FIXED CHARGES
   - C_3 - INTERIM REPLACEMENT
   - B_1 - FUEL COST
   - B_2 - FIXED CHARGES
   - B_3 - OPERATION & MAINTENANCE
9. INITIAL POWER VALUE BASED ON A TOTAL VALUE OF 3.1 ¢/KWH AND AN ASSUMED DISTRIBUTION AS NOTED IN THE REPORT

TABLE 1
PAGE 1 OF 2

FUEL ESCALATION RATE (F)	YEAR	COMPARATIVE PRODUCTION (3.1 ¢/KWH)		OIL REPLACEMENT VALUE $16.50/BBL (2.549 ¢/KWH)		OIL REPLACEMENT VALUE $20.07/BBL (3.1 ¢/KWH)	
-	-	NO INFLATION	4 %/YR INFLATION	NO INFL.	4 %/YR	NO INFL.	4 %/YR
0.01	1979	0.54	0.54	0.45	0.45	0.55	0.55
	1980	0.55	0.55	0.45	0.45	0.55	0.55
	1987	0.57	0.57	0.49	0.49	0.60	0.60
	1990	0.61	0.65	0.54	0.60	0.66	0.73
	1995	0.63	0.77	0.57	0.77	0.69	0.94
	2000	0.65	0.90	0.60	0.96	0.73	1.17
	2010	0.69	1.29	0.66	1.52	0.80	1.85
	2017	0.72	1.68	0.71	2.06	0.86	2.51
	2018	0.73	2.20	0.72	2.16	0.88	2.62
0.03	1979	0.54	0.54	0.45	0.45	0.55	0.55
	1980	0.55	0.55	0.46	0.46	0.57	0.57
	1987	0.63	0.63	0.57	0.57	0.69	0.69
	1990	0.66	0.71	0.62	0.69	0.75	0.84
	1995	0.72	0.89	0.70	0.94	0.85	1.14
	2000	0.75	1.06	0.74	1.19	0.90	1.45
	2010	0.80	1.54	0.82	1.88	1.00	2.29
	2017	0.84	2.02	0.88	2.56	1.07	-
	2018	0.85	2.05	0.88	2.67	1.07	-
0.05	1979	0.54	0.54	0.45	0.45	0.55	0.55
	1980	0.56	0.56	0.47	0.47	0.57	0.57
	1987	0.69	0.69	0.66	0.66	0.80	0.80
	1990	0.76	0.83	0.76	0.85	0.92	1.03
	1995	0.88	1.11	0.94	1.26	1.14	1.53
	2000	0.92	1.34	0.99	1.59	1.20	1.93
	2010	0.99	1.98	1.09	2.51	1.32	-
	2017	1.04	2.61	1.17	-	1.42	-
	2018	1.05	-	1.18	-	1.44	-

BENEFIT-COST RATIO
GOOSE POINT PROJECT

TABLE 2

PROJECT:	GOOSE POINT MAINE	HALF-MOON COVE CORPS DERIVED	HALF-MOON COVE LABERGE
PROJECT COSTS (JANUARY 1979 LEVEL)			
DAMS	18,000,000	1,425,150	1,215,000
LOCKS	7,000,000	-	-
GATES	47,150,000	2,200,000	2,546,000
POWERHOUSE	178,600,000	13,370,000	14,972,000
SERVICE FACILITIES	1,012,500	75,000	-
RELOCATION	8,500,000	-	-
FISHWAYS	2,300,000	500,000	-
BASIC COSTS	262,562,500	17,570,150	18,733,000
CONTINGENCY	39,384,375	2,633,520	1,873,000
ENGR., SUPRV., & ADMIN.	30,194,687	1,757,015	1,199,000
REAL ESTATE	1,300,000	500,000	-
SERVICE EQUIPMENT	600,000	200,000	-
PROJECT COST	334,041,562	22,662,685	22,065,000
INTEREST DURING CONSTRUCTION	34,448,036	1,558,060	1,395,000
COST OF INVEST.	368,489,599	24,220,745	23,460,000
ANNUAL COST			
OPERATION & MAINT.	945,000	70,000	314,000
MAJOR REPLACEMENT	364,500	27,000	58,000
FIXED - INTEREST	25,366,518	1,665,175	1,642,000
AMORTIZATION		2,160	58,000
TOTAL AN. COST	26,676,018	1,764,335	2,049,000
PRODUCTION DATA			
CAPACITY (MW)	135	10	10
CAPACITY FACTOR	0.396	0.433	0.433
ANNUAL ENERGY (KWH)	468,000,000	37,894,000	37,894,000
PROJECT LIFE (YEAR)	100	100	30

TABLE 3

Appendix I

Discussion on Relative Price Shift Analysis

The U.S. Army Corps of Engineers (New England Division) in the report titled, "Preliminary Report on the Economic Analysis of the (Cobscook Bay Tidal Power) Project", state that;

> "..., in the case of general inflation, it makes no difference whether we use (1) benefits and costs all stated in construction period prices and a discount rate containing no inflationary premium, or (2) benefits and costs in the prices of the period in which each is incurred and a discount factor that fully compensates for the rate of inlation."

However, it will be shown that this conclusion does not necessarily apply to some of the cost components for the period after construction.

In this exercise, the project cost, C_i, for each year of operation, i, is assumed to be comprised of three elements - C_{1i} (operation and maintenance), C_{2i} (fixed charges), and C_{3i} (major replacement). Similarly, annual project benefits, B_i, when compared to the oil replacement value at a combined cycle plant are classified as follows; B_{1i} (fuel cost), B_{2i} (fixed charges), and B_{3i} (operation and maintenance cost). Therefore;

$$C_i = C_{1i} + C_{2i} + C_{3i} \tag{A.1}$$

and

$$B_i = B_{1i} + B_{2i} + B_{3i} \tag{A.2}$$

If we let C_o equal the initial construction cost, then the present value of net benefits is expressed as follows:

$$PV = -C_o + \frac{(B_1 - C_1)}{(1 + D_1)} + \frac{(B_2 - C_2)}{(1 + D_1)^2} + \ldots + \frac{(B_n - C_n)}{(1 + D_1)^n} \tag{A.3}$$

where D_1 is the the discount rate in the face of steady prices; i.e., no inflation. However, for the case where an inflation rate, I, exists we then have to use the following expression:

$$PV = -C_o + \frac{(B_1 - C_1)(1 + I)}{(1 + D_2)} + \ldots + \frac{(B_n - C_n)(1 + I)^n}{(1 + D_2)^n} \tag{A.4}$$

where D_2 is the discount rate derived from the market rates of interest with an inflationary premium. The Corps assumed that $(1 + D_2)$ was equal to $(1+I)(1+D_1)$ which reduced the above equation (A.4) to the following form;

$$PV = -C_o + \frac{(B_1 - C_1)(1 + I)}{(1 + I)(1 + D_1)} + \ldots + \frac{(B_n - C_n)(1 + I)^n}{(1 + I)^n (1 + D_1)^n} \tag{A.5}$$

and which was then used for the basis for the earlier statement.

But once the plant is in operation the fixed charges remain constant even with the presence of inflation. The sum of benefits and costs can be broken down into the following expressions;

$$B_1(1 + I) = [B_{1i} + B_{2i}/(1+I) + B_{3i}]\ (1 + I) \tag{A.6}$$

and

$$C_1(1 + I) = [C_{1i} + C_{2i}/(1+I) + C_{3i}]\ (1 + I) \tag{A.7}$$

By placing these expressions into the equation for present value (A.5) for one annual cost and benefit component, we then have:

$$\frac{(B_i - C_i)(1 + I)^i}{(1 + I)^i\,(1 + D_1)^i} = [(B_{1i} + B_{2i}/(1+I)^i + B_{3i})(1 + I)^i -$$

$$- (C_{1i} + C_{2i}/(1+I)^i + C_{3i})(1 + I)^i]\,\frac{1}{(1 + I)^i(1 + D_1)^i}$$

$$= \frac{[(B_{1i} + B_{3i}) - (C_{1i} + C_{3i})]}{(1 + D_1)^i} +$$

$$+ \frac{[(B_{2i} - C_{2i})]}{(1+I)^i(1+D_1)^i} \qquad (A.7)$$

The second term of Eqn. (A.7) reduces to $[(B_{2i} - C_{2i})/(1 + D_2)^i]$ which does contain the inflationary premium built into the discount rate for the prices of the selected time period. The relevance of this comment is noted elsewhere in this paper; however, it should be mentioned that B_{2i} and C_{2i} can be considered benefits and costs, respectively, for any year, i, on the basis of construction period estimates or for current prices under an assumed inflation rate. The complication enters whenever construction period prices are used in reference to the presence or absense of an inflation rate.

The introduction of a fuel escalation rate, F, above the general rate of inflation adds another consideration into these calculations, namely;

$$\frac{B_{1i}(1 + I + F)^i}{(1 + I)^i(1 + I)^i} = \frac{B_{1i}(1 + I)^i(1 + F)^i}{(1 + I)^i(1 + I)^i} \qquad (A.8)$$

if we assume that $(1 + I + F)$ is equal to $(1 + I)(L + F)$. The relative difference in this assumption is tabulated below for various values of inflation and fuel cost escalation (%/year):

		$[(1+I+F)/(1+I)(1+F)]^k$				
I	F	$k=1$	2	5	10	20
.02	.01	.9998	.9996	.9990	.9981	.9961
	.03	.9994	.9989	.9971	.9943	.9886
	.05	.9991	.9981	.9953	.9907	.9815
.04	.01	.9996	.9992	.9981	.9962	.9924
	.03	.9989	.9978	.9944	.9898	.9778
	.05	.9982	.9963	.9909	.9818	.9640
.06	.01	.9994	.9988	.9972	.9944	.9889
	.03	.9984	.9967	.9918	.9836	.9675
	.05	.9973	.9946	.9866	.9734	.9474
.10	.05	.9957	.9914	.9785	.9575	.9169

APPENDIX II

LIST OF EQUATIONS

A. PRESENT VALUE OF NET BENEFITS FOR A SELECTED YEAR

$$(PVNB)_i = \left(B_1(1+F)^i + \frac{B_2}{(1+I)^i} + B_3 \right)_i \frac{1}{(1+D_2)^i} - \left(C_1 + \frac{C_2}{(1+I)^i} + C_3 \right)_i \frac{1}{(1+D_1)^i}$$

WHERE:
- I - ANNUAL INFLATION RATE
- F - FUEL COST ESCALATION RATE ABOVE INFLATION
- i - NUMBER OF YEAR AFTER THE END OF CONSTRUCTION AND THE START OF PLANT OPERATION

FOR THE ALTERNATIVE COMBINED CYCLE PLANT, THE FOLLOWING TERMS ARE DEFINED:
- B_1 - FUEL COST PER YEAR
- B_2 - ANNUAL FIXED COST
- B_3 - ANNUAL COST OF OPERATION AND MAINTENANCE
- D_2 - DISCOUNT RATE WITH NO INFLATIONARY PREMIUM (.105)

SIMILARLY, FOR THE TIDAL PLANT:
- C_1 - ANNUAL COST OF OPERATION AND MAINTENANCE
- C_2 - ANNUAL FIXED CHARGES
- C_3 - ANNUAL COST OF INTERIM REPLACEMENT [illegible]
- D_1 - DISCOUNT RATE (0.06875)

B. BENEFIT COST RATIO (BCR)

CASE 1: BEFORE PLANT OPERATION

$$BCR = \frac{\left(B_1(1+F+I)^i + B_2(1+I)^i + B_3(1+I)^i \right)}{\left(C_1(1+I)^i + C_2(1+I)^i + C_3(1+I)^i \right)}$$

(i = NO. OF YEARS FROM THE YEAR OF PREVAILING COST)

ASSUME THAT,

$$(1+F+I) = (1+F)(1+I)$$

THEN,

$$BCR = \frac{\left(B_1(1+F)^i + B_2 + B_3 \right)}{\left(C_1 + C_2 + C_3 \right)} \quad \frac{(1+I)^i}{(1+I)^i}$$

CASE 2: AFTER PLANT CONSTRUCTION (i = NO. OF YEARS FROM THE INITIATION OF OPERATION FOR CONSTRUCTION PERIOD COSTS)

$$(BCR)_i = \frac{\left(B_1(1+F+I)^i + B_2 + B_3(1+I)^i \right)}{\left(C_1(1+I)^i + C_2 + C_3(1+I)^i \right)}$$

$$= \frac{\left(B_1(1+F)^i + \frac{B_2}{(1+I)^i} + B_3 \right)}{\left(C_1 + \frac{C_2}{(1+I)^i} + C_3 \right)} \quad \frac{(1+I)^i}{(1+I)^i}$$

THE DISCOUNT RATE IN RELATIVE PRICE SHIFT ANALYSIS

by

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Prepared for

SYMPOSIUM ON RELATIVE PRICE SHIFT ECONOMIC ANALYSIS
AS APPLIED TO PUBLIC POWER PROJECTS

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Relative price shift analysis represents an approach to benefit cost analysis of long lived projects in which an effort is made to incorporate information on expected future changes in relative prices in the estimates of benefits and costs. In the absence of any better basis for forming expectations or predictions of future relative prices, the typical practice has been to assume that increases and decreases in the relative prices of particular commodities were equally likely and that, therefore, the expected value of future relative prices was equal to the present set of relative prices. However in some situations, other expectations concerning future relative price movements may be justified. For example, some argue that the relative price of fossil fuel is more likely to rise than to fall over the next, say, fifty years. It seems clear that benefit cost analysis should be based on the most reasonable expectations of the future. Thus, where acceptable predictions can be made concerning future relative prices, these should be incorporated in the estimates of benefits and costs that are used to calculate the benefit-cost ratio.

The magnitude and direction of future relative price movements cannot be known with certainty. Any statement about expected future relative prices has a margin of uncertainty surrounding it. In formal terms, a statement about relative price changes can be treated as an expected value or mean of a subjective-probability distribution over alternative possible futures. This probability distribution has a variance. It is important that statements about expected values be accompanied by some indication of the estimated variance or margin of likely error surrounding the estimate. For example, an analyst might state that the most likely behavior of fossil fuel prices over the next fifty years is an increase at an annual rate of 3%. But how confident is the analyst in this expectation? She may be 95% sure that the true value will turn out to lie within the range 2.5-3.5%; or she may be much less certain, feeling that there is a 95% chance that the true value could be as low as -2% and as high as +8%.

Decision makers are likely to be very interested in the degree of confidence with which estimates of future relative prices are held. Decision makers deserve to be told about these confidence intervals. And, of course, this statement is true whether the analyst expects relative prices to remain constant or to change.

What does this have to do with the discount rate? One question in the choice of a discount rate is whether (and if so, how) to incorporate adjustments for risks and uncertainty in the discounting process. The discussion of relative price shift analysis focuses our attention on the inherent uncertainty regarding estimates of benefits and costs, and forces us to consider the question of risk in the selection and utilization of a discount rate. I will return to this point in a moment.

I turn now to a consideration of the appropriate conceptual and empirical bases for selecting a discount rate. A review of the principles underlying benefit cost analysis and discounting should provide a basis for answering questions about the treatment of inflation and risk in the selection of a discount rate. The basic rationale for employing any form of benefit cost analysis is that the government in its role as an investor is attempting to reallocate resources so as to maximize economic welfare as reflected in the total value of goods and services produced by the economy. Maximizing economic welfare requires that the social benefit or return on each dollar spent by the government at least equal its opportunity cost, that is, the private benefits or returns forgone by the diversion of resources from private to public uses.

When current resources are diverted from private uses to produce current benefits, market prices can usually be taken as measures of opportunity costs. By similar reasoning when the government project involves expenditures today in anticipation of future benefits, one should look to private market interest rates as a measure of the opportunity cost of time. In a very simple, hypothetical economy where all investments are riskless, taxes are zero, and there are no market imperfections, there can be only one interest rate. All borrowers, lenders, and investors, including the government, would use this interest rate in their financial planning and decision making. However, in the real world, there are differences in riskiness across investments, various financial instruments for allocating risks, differences in the taxation of income from various financial instruments, and market imperfections such as the regulation of interest rates on savings accounts. These factors all lead to a multiplicity of interest rates in financial markets. Hence, the controversy over which rate or combination of rates should be used to guide public investment decisions.

Let us ignore for the moment the problems posed by inflation and uncertainty concerning future returns. There will still exist a variety of interest rates and rates of return across different assets and forms of investment. The opportunity cost of diverting one dollar from private to public investments will depend upon which private investments are forgone. And this in turn depends on the method of financing the public investment, among other things.[1] First, suppose that the public

[1]For further discussion, see Robert H. Haveman, "The Opportunity Cost of Displaced Private Spending and the Social Discount Rate," Water Resources Research, 5, No. 5 (October, 1969), 947-957.

investment is financed through borrowing in capital markets in such a way that there is a one for one displacement of private investment in manufacturing. Then, the opportunity cost of the public investment is the pre-tax rate of return on private investments in manufacturing. Alternatively, suppose that the public investment is financed through an increase in taxes on personal income. Then, the opportunity cost is spread across households in proportion to the distribution of the burden of the federal personal income tax. The opportunity cost is a weighted average of the marginal interest rates faced by each household in their roles as net borrowers or lenders.

As will be seen shortly, these two alternative means of financing public investments can lead to significantly different estimates of opportunity costs and discount rates. Which assumption is more appropriate in the case at hand, that is investments in hydro-powered electric generating facilities? I believe that the assumption of displacement of private investment is more realistic. The construction of hydro-powered generating facilities will make it unnecessary to construct additional (presumably more costly) privately financed fossil fuel generating facilities. Furthermore, depending upon cost allocation formulas and the interest rate used in the repayment analysis, all or at least a major part of the cost of constructing the federal hydro project is recovered through charges for the energy produced. Thus, in the longrun, the route of financing is not through the federal tax structure. Therefore, I conclude that the appropriate measure of opportunity cost, and the correct discount rate for use in benefit cost analysis is the pre-tax rate of return on private investme

With inflation, observed market interest rates and rates of return on investment reflect the sum of real rates of return or opportunity cost and the expected future rate of price inflation. If the benefit cost analysis abstracts from inflation of all prices (that is, is based on constant dollars) and focuses only on possible changes in relative prices, then observed market rates of return must be deflated by the expected inflation rate before being incorporated in the benefit cost analysis. In other words, if the benefit cost analysis is carried out in real terms, then the discount rate should be based upon real rates of return and opportunity costs.

As noted earlier, the future cannot be known with certainty. The degree of uncertainty and risk (that is, the range of possible outcomes) varies across investment alternatives. Private investors have to be compensated with a higher expected rate of return in order to induce them to invest in more risky projects. The question is should the discount rate used to guide public investments in more risky areas incorporate a risk-taking premium. There are two arguments for using a risk free rate for public sector investment decisions. But I believe that neither argument is applicable to hydro-electric power investments, at least under present institutional arrangements.

The first argument is based on <u>risk pooling</u> as is done by large insurance companies. If with a large number of similar projects the risks on individual projects cancel out, then it would be appropriate to utilize a risk-free discount rate. However, the major component of the risks associated with hydro-powered development concerns uncertainty about demand, techological change, and future trends in fossil-fuel prices. These uncertainties affect all hydro-power projects in the same manner and thus do not cancel out.

The second argument is based on <u>risk spreading</u>. If, for example, benefits are spread across a large number of people, increases or decreases in realized benefits become very small on a per capita basis. In the limit, the risk per person is too small to worry about and can be ignored. However, many of the risks associated with hydro-power developments are borne not by the population as a whole but rather by the consumers of power generated by the project. Since these risks are not widely spread, they may be significant on a per capita basis. This should be reflected in the discount rate chosen for project analysis. Thus, I conclude that unless the risk spreading or risk pooling arguments can be applied, the appropriate discount rate for public investments should incorporate the risk premium observed in similarly risky private investments.

The most widely cited estimate of the pre-tax rate of return on private capital investment is based on the work of Stockfisch.[2] He estimated that in the mid-60's the pre-tax rate of return was between 10-15%. This figure was not adjusted for inflationary expectations. During this time, inflation was only in the range of 1-2%. So, the real pre-tax rate of return lay in the range 8-13%. A more recent estimate places the real rate of return on private investment at between 8½-10½%.[3] This compares with an estimate of the real opportunity cost of investment finance through personal income taxes in 1966 between 5 and 6% prepared by Haveman.[4]

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[2] See J.A. Stockfisch, "The Interest Rate Applicable to Government Investment Projects," reproduced in the Congressional Record-Senate, Sept. 22, 1967, pp. S13467-S13472.

[3] See Steve H. Hanke and James Bradford Anwyll, "The Political Economy of the Discount Rate Controversy," Public Policy, in press.

[4] Haveman, op. cit.

Present federal procedures call for using a discount rate computed from the average yields on long-term government securities. The procedures also limit increases in the effective discount rate to no more than 1/4% per year. The present official discount rate is 6 7/8%. This figure is below the estimates of the real pre-tax rate of return on private investment. There are three major reasons why the government bond rate and the real pre-tax rate of return might differ. First government bonds are substantially less risky than private investment. Second, government bonds are instruments of monetary and fiscal policy and their prices and yields are effected by factors quite independent of real rates of return in the private sector. Finally, as market rates of return, government bond rates will include inflationary premia.

To summarize, my major conclusions are as follows: (1) the discount rate for evaluating federally financed hydro projects should be the real opportunity cost of private investment; (2) the discount rate should incorporate a risk premium; (3) the discount rate should not incorporate an inflationary premium since the benefit-cost analysis is conducted in real terms; (4) the best estimate of the appropriate discount rate is 8½-10½%; (5) because they incorporate an inflationary premium and do not carry the same degree of risk and risk premia, government bond rates cannot be used as an estimate of the correct discount rate.

IDENTIFYING AN APPROPRIATE MEASURE OF BENEFITS FOR EVALUATING TIDAL POWER IN COBSCOOK BAY

This paper addressed two questions posed by the Corps of Engineers: (1) Should a <u>capacity</u> credit be included in benefits when evaluating a single-pool tidal project? (2) What is the appropriate measure of <u>energy</u> benefits from this type of project?

(1)

In general, the alternative cost approach to measuring benefits of a given hydroelectric project requires choosing an alternative having similar capacity and output characteristics. In the case of a single-pool tidal project, however, there is no unambiguous alternative. All of the real alternatives (excepting wind power) would have dependable capacity -- dependable in the sense of being available when needed to meet system peak load. This is not true of a single-pool tidal project; capacity and output in such a project vary with the tidal, hence, lunar cycle, whereas the daily load curve of a typical utility system reflects the solar cycle. The appropriate alternative to energy from such a tidal plant therefore would be a "capacityless" generating source, implying no capacity credit for project benefits.

If tidal energy enters an electrical grid having adequate storage capacity, it can be "retimed" to meet peak loads. This would undoubtedly be the case for Cobscook tidal energy; such energy might flow into storage directly or might displace other energy (excepting at those times when maximum tidal generation coincided with the system peak) thus preserving storage elsewhere for retiming. It can be argued, however, that the "credit" for retiming properly belongs to the storage facility itself and not to the original but intermittent generating source. While I believe this is a logical inference to draw, I am open to opposing viewpoints if or where it can be shown that the capacity benefit might be shared.

The appropriate measure of <u>energy</u> benefits for a tidal power project is the cost of energy from the next best alternative. Such a benefit measure must of course take account of differences in transmission distance between generating station, storage facility (where applicable), and market. The alternative source of generation must be identified by recourse to <u>reality</u>: What in fact is likely to be the alternative source of incremental energy in the particular region over the relevant time period?

It is customary to proceed by comparing the cost of electric energy from the project to be evaluated with costs of energy from a generating station that would be built in lieu of the project. It must be recognized, however, that this is a somewhat arbitrary procedure which does not recognize the <u>range</u> of substitutes actually existing. Substitutes for electric energy in fact include alternative forms of energy (e.g., natural gas), and also alternative labor or capital inputs (manual processes, insulation, solar construction). Thus, the conventional procedure oversimplifies by assuming that the next best alternative (and hence proper measure of benefits) is an incremental quantity of electric energy.

It also is normal procedure to conjure up a hypothetical alternative (generating plant) that would operate with something like the same output to capacity relationship (see above) as the project which is to be evaluated. The rationale here is that, even in the case of energy alone (i.e., neglecting capacity) similar parts of the future load curve would have to be met by projects having similar characteristics. This, again, is a reasonable assumption if substitution possibilities are minimized by the limited size of the generating grid. In today's economy, however, with grids increasing in extent and capacity, and with increasingly varied forms of both generation and storage, the above rationale is considerably weakened. The next best alternative to energy from the tidal project might well have hybrid characteristics, and may indeed be difficult to specify the longer forward one looks.

Evaluating tidal power benefits from a Cobscook Bay plant would be particularly difficult on this last score -- given the very long life of the tidal plant -- if the project included dependable capacity, as in a two-pool scheme. That is, the tidal plant probably would be producing energy over a period of time equivalent to the life spans of three thermal alternatives. (This of course assumes that neither silting, corrosion, nor natural disaster would shorten the life of a tidal plant to less than that of a conventional hydro station.) Those alternatives might be expected to change as technology itself improved. Fortunately, the present task is simplified (somewhat) by the absence of dependable capacity. The only "alternative" that needs to be measured is the energy itself.

As one looks at the New England grid today and to the end of the century at least, it seems likely that incremental energy will be supplied largely, if not entirely, by oil-fired generation. Nuclear plants now on-line and under construction are certain to be used for base load (when they are operating at all), and present oil-fired plants will be used to fill out the load curve only as necessary. The extent to which these latter plants will have to be used, in other words, will depend on nuclear down-time, hydro conditions, the availability of lower cost coal and wood-fired generation (and Canadian energy), and the evolving shape of regional load curves. Whatever the mix, oil, in my opinion, is going to be the source of displaced energy.

If this appraisal is correct, the task of evaluating energy benefits at Cobscook Bay is simply one of measuring (again allowing for distance) the future energy costs of oil-fired generation. This consideration, incidentally, should lay to rest any disputes about whether nuclear energy should be counted as the appropriate alternative if the Cobscook Bay plant could be cranked up to a higher-than-40% capacity factor. It should not. Whatever the theoretical alternative might be in an abstract grid, the facts of life in New England are that the alternative will be electricity generated by OPEC oil.

At present, the average thermal efficiency (heat rate) of fossil fuel generation in New England is about 10,100 btu/kwh. If we take that figure to be representative of the thermal efficiency of generation which might be displaced by energy from a tidal plant, and if we assume (with the Corps) a heat content of 5,900,000 btu per barrel of residual fuel oil, the <u>fuel cost</u> of the displaced energy is approximately 4 cents per net kilowatt-hour when oil is $24.00 per barrel. That figure must be adjusted upwards to cover operation and maintenance expenses, and downward to reflect the greater distance of tidal generation from markets than the displaced fossil fuel generation.

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SUMMARY

SYMPOSIUM ON RELATIVE PRICE SHIFT ANALYSIS AS APPLIED TO PUBLIC POWER PROJECTS

SPONSORED BY

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The static quality of conventional benefit-cost analysis for assessing public investment in power projects has proved inadequate in a period of unstable energy supply and changing technological and social conditions. To better account for the fluid or dynamic nature of economic relationships and values, relative price shift analysis has been developed as a refinement over earlier techniques. To gauge opinion of the technique's usefulness and validity, the Balanced Growth Project of the University of Maine at Orono, the Maine Office of Energy Resources, the Maine State Planning Office, and the New England Division of the Army Corps of Engineers sponsored a symposium on November 27, 1979. At that symposium, individuals from public agencies, private companies, and higher education explored the merits and limitations of relative price shift analysis through the presentation and discussion of working papers.

The discussion, for the most part, was general rather than technical, and most participants - both panelists and members of the audience - concluded that relative price shift analysis was an improved and more realistic measure of a project's costs and benefits. Unresolved though, were a number of major issues relating to economic analysis of any sort. Considerable discussion ensued over the appropriate calculations of costs and methods for financing power projects, over the quality and accuracy of assumptions used in projections, over the factors which should be included or excluded in analysis, and over the basis of comparison for evaluating one type of project - hydropower - over alternative configurations.

Nearly all participants challenged the methods for calculating the costs of financing for public power projects. The discount rate of 6-3/8% authorized for use by the Water Resource Council was viewed as an arbitrary and unreasonably low figure that does not accurately reflect real financing costs and which skews cost analysis in favor of public investment. Since public investment in power projects diverts capital from private investment, some felt that the costs of foregone opportunities should be valued at real market prices or real return on private investment, a rate of between 8½% to 10½%, as suggested by panelist A. Myrick Freeman III, or at a compromise "social discount rate" to be applied equally to comparative analysis of public and private investments, as suggested by William Beardsley.

The validity of low governmental discount rates based on risk pooling or spreading was debated as well. Freeman, again, argued that risks for hydropower are actually concentrated among a limited number of people and are therefore significant on a per capita basis. Additionally, the uncertainties about hydropower are not singular but affect all hydro projects and therefore should be included as risk premiums in public discount rates. One member of the audience, Clark Irwin, noted that estimates of financing costs based on government bonds failed to include the costs of foregone tax revenues.

Though public investment in power projects was viewed by most as appropriate, there were implied differences of opinion as to the desired extensiveness of government financing. One member of the audience, Representative Judy Kany, was particularly in favor of public measures to encourage financing utilities in Maine through provision of tax exempt bonds for utility construction or the adaptation to Maine of other measures practiced in the country. Others were more cautious on their assessment of the balance needed and one, Myrick Freeman, argued that if there are benefits above and beyond economic considerations they should be identified and quantified and not imperfectly reflected in subsidized interest rates.

Accuracy of the assumptions used in projections was frequently cited as necessary in determining a project's benefits and costs. In relative price shift analysis, escalation rates for particular commodities such as fuel, and explicitly oil, were viewed as fraught with uncertainty yet critical to valid judgement. Using the Army Corps of Engineers' assessment for tidal power development in Cobscook Bay as an example, several participants noted that price increases had already exceeded projected prices. One panelist, Charles Colgan, urged the use of the Department of Energy's simple equilibrium models to reflect long range demand and supply characteristics and to predict OPEC increases in prices, an exercize that could reflect an annual escalation rate of 4%, enough to achieve unity in Cobscook Bay Tidal project. Another panelist, Norman Laberge pointed out that fuel escalation projections need to be accompanied by a statement on the presence or absence of inflation, arguing that the inclusion of inflation estimates decreases the margin between the present value of a combined cycle plant and the value of a tidal project, placing the latter in a more favorable light.

A potential discrepancy in assumptions was implied in different figures cited for the assumed energy efficiency of thermal alternatives. The Corps cites an efficiency of 40%. Colgan, in his presentation, argued that 30% is a realistic figure, and one which could improve the position of tidal power vis-a-vis conventional thermal units.

Most participants recognized the highly speculative nature of predictions, particularly those over long terms. Two panelists, Gerald Dawbin and Myrick Freeman suggested that projections be labeled for their degree of uncertainty or confidence level by attaching "degrees of risk" or "estimated variance or margin of likely error surrounding the estimate".

In fact, several individuals reasoned that as the margin of uncertainty increased over time, economic analysis should be limited to the near term perhaps no more than 30 years. William Beardsley argued that long range predictions based on comparisons limited to two types of energy generation, such as tidal and combined cycle oil, fail to account for technological change and innovation and misrepresent benefits. Others, such as Charles Colgan and Gerald Dawbin felt that long range assessment, though imperfect, was critical, particularly in weighing the costs and benefits of a long lived project with a short term one such as combined cycle oil. Freeman felt that to look at the future more realistically, assessment should include a relative technology shift as well as price shift.

The views as to what related or ancillary costs and benefits should be included in an economic analysis of a project varied widely - Lawrence G. Hines asserted that inclusion of such concerns, particularly for aims different than the primary prupose of a project, has the affect of inflating benefits, in fact leads to "agressive benefit recruitment", to justify a project that may otherwise fall far short of unity. He cited many examples, among them the benefits cited for downstream Canadian power production resulting from

Dickey-Lincoln, without including the costs of importing that power. Hine's skepticism was not shared by others. A whole range of factors was offered to be considered for inclusion. Among them were the following:

- The assessment of the costs of complying with environmental safeguards and mitigating environmental effects;

- the inclusion of the costs for escalating safety costs, construction standards, and quality control;

- the recognition of the national balance-of-trade deficits resulting from purchase of foreign funds and materials;

- an estimate of the energy efficiency of projects being compared and the cost of wasted energy from a finite resource such as oil;

- the internalization of job or employment benefits;

- the inclusion of area development possibilities including new industries, tourism, etc.; and

- the synchronization of energy outputs of a project with needed time through storage or displacement of other energy.

Though participants differed as to the variety of measures appropriate for inclusion in the analysis of alternate projects, all felt that the examination of external factors had to be carried out consistently in comparing the costs of one project versus alternatives.

Interwoven throughout the presentations and discussions was the concern over the integrity of selecting alternative energy projects for comparison. The solution of a "least cost" alternative was felt by some to be imperative, and that comparison of a hydropower project with methods other than least cost can assure an above unity benefit/cost ratio for hydropower. Others felt such a method would fail to reflect changing priorities and the desirability of one mode over another.

The use of a single alternate posed a variety of problems for some. Charles Colgan argued that an alternative"should be technically comparable to the principle project," and the projects being compared "should be of the same scale and capable of performing the same task". Yet William Beardsley argued that a single alternative approach particularly such as combined cycle oil, ignores technological change and even recent government policies on the use of oil, and fails to account for the "irregular stream of costs and benefits' over time. William D. Shipman pointed out that the solution of a single alternative for comparison "does not recognize the range of substitutes actually existing", including different forms of energy, alternative capital or labor possibilities, and differences in capacity credit and energy benefits. In the case of some single-pooltidal power he argued that no unambiguous alternative exists and that rather an alternative "might well have hybrid characteristics."

Such a mix was favored too by Philip Hastings who stated, "The Planning Process is not a simple comparison of one type of unit versus another. The objective is to minimize <u>total</u> cost to the customer over <u>time</u>." Additionally, a unit-to-unit comparison may not reveal all potential costs and benefits and may not assess the impact on or displacement of the region's power supply.

Confronted by the plethora of possible alternatives from which to select, at least two participants, Shipman and Dawbin felt that oil fueled power should be selected for purposes of comparison because it was most likely to be the energy displaced by hydropower, particularly in New England. Charles Colgan, too, selected an oil based alternative because the technology is well established and of known use and cost. Other technologies such as nuclear plants and gas fired generators were viewed as imbalanced in favor of inexpensive fuel costs or capital costs and thus not fair comparisons, though some participants disagreed.

Though the panelists as a whole agreed that relative price shift analysis was a superior approach to standard benefit cost analysis, and agreed that a number of issues jeopardized the credibility of any analysis, there was considerable variety and disparity of views among them on nearly every issue. The science of prediction, it seems, is affected by differing priorities, values and assumptions. The symposium defined the issues but did not provide a consensus on direction.

SUMMARY

SYMPOSIUM ON RELATIVE PRICE SHIFT ANALYSIS

Submitted by

Wayne Oliver, Recorder

The purpose of the Symposium on Relative Price Shift Analysis held in Portland, Maine, on November 27, 1979, was to discuss the validity of relative price shift analysis as a way of analyzing the economics of hydroelectric projects. Relative price shift analysis is basically a more refined form of life cycle cost methodology which attempts to compare costs and benefits of projects in terms of real price changes over time. This approach provides an improvement over conventional static benefit-cost analysis by determining the real changes in costs and benefits over the life of a project.

To provide a proper perspective of discussion by panelists on the issue of relative price shift analysis, it is necessary to briefly describe the use of benefit-cost analysis as a policy tool. Originally, Congress and other members of the political bureaucracy looked at benefit-cost analysis as a way of ranking projects for appropriations. Projects competed for appropriations, and those with the highest benefit-to-cost ratios received the funding. Economists began using benefit-cost analysis as a means of answering the question of whether resources should be used in the private or public sector based on the most productive and efficient use of those resources. Since the opportunity cost of a public project was private sector output, investment in public projects was viewed as a tradeoff for investment in the private sector. Interestingly, the symposium really brought to light how benefit-cost analysis was viewed by various members of the panel from different backgrounds and constituencies.

Discussion of relative price shift analysis in particular and benefit-cost analysis in general focused on the following issues:

1. What is the appropriate discount rate?
2. What is the appropriate alternative that any hydro project should be compared to?
3. How should externalities be accounted for?
4. What is the appropriate time frame for analysis of the economic benefit and costs of a hydro project?
5. How do we account for future technology?
6. How do we account for the problems of estimating future benefit and cost components such as fuel prices?
7. Should ancillary benefits be included?

8. How does the question of variable powers reliability effect utility planning?

9. Should one definitive ratio be used or would setting up a confidence interval of benefits and costs be more appropriate?

10. Is relative price shift analysis a more effective way of measuring costs and benefits?

As a means of providing a summary and evaluation of the panel discussion, the following outline will be followed:

1. Key issues of discussion.

2. Questions and analysis of those issues.

3. Panel member discussion.

I. A. What is the appropriate discount rate?

B. Determination of the appropriate discount rate (based on riskiness in use of funds) is very important in evaluating the benefits and costs of a particular project. Use of an improper discount rate will lead to a misallocation of resources.

In evaluating which is the proper discount rate, the opportunity cost of the investment has to be determined. For example, if the opportunity cost of using funds to construct a tidal power project is private investment funds, then the discount rate should reflect the private cost. When cost-benefit analysis was originally developed, the true opportunity cost of public projects could be measured by the interest rate on long term government securities. However, in cases where capital markets are tight, public investment may crowd out private investment. If this is indeed the true opportunity cost, that is, the interest rate on private funds, then in today's market a private interest rate or a rate somewhere between a public and private rate may be desirable.

C. Panel Discussion Concerning the Appropriate Discount Rate. A number of panel members provided discussion on the appropriate discount rate. Following is a summary of views of those who discussed this issue:

William Beardsley - Basically, made two points concerning use of the appropriate discount rate:

1. A single rate should be used.

2. The rate chosen must be the correct rate. If not, a misallocation of resources will occur. Discount rates are treated

similar to the price mechanism. A low discount rate will result in investment funds flowing into that area. If rate is lower than the true market rate, then an inefficient allocation of use of the funds could occur.

Mr. Beardsley felt that the appropriate social discount rate falls somewhere between the private and public rates.

Myrick Freeman - Dealt specifically with use of a correct discount rate. Professor Freeman noted that the rationale for benefit-cost analysis is because the Government is trying to allocate resources to maximize society's welfare. The opportunity cost of public investment could be financed through taxes or through crowding out private investment. If private investment is crowded out, the correct discount rate should be the pre-tax rate of return on private investment. The risk premium of using these funds has to be considered. Since Government bonds (long-term securities) are less risky than private investment financing, the discount rate used may be artificially low. Finally, a real rate of return and not a market rate should be used. At the present time, the real rate of return is between 8.5% to 10.5%.

Norman Laberge - Suggested that the public discount rate should be used because the projects are very important to the interest of society.

One important exchange on this issue took place between Ms. Canan and Professor Freeman. Ms. Canan noted that since the generation of electricity is considered in the public interest, could tax exempt bonds be sold to build such facilities? This would serve to lower the discount rate. Professor Freeman indicated that such a subsidized interest rate may lead to a misallocation of resources. Professor Shipman then noted that such subsidized interest rates may not be inefficient and may actually stimulate competition which would be healthy.

II. A. What is the appropriate alternative that a hydro project should be compared to?

B. This issue raised a number of interesting suggestions as to the appropriate alternative ranging from nuclear power to oil conservation. Basically, in making such a determination, the reasons for the project should be considered. If the major reason to construct a hydro project is to produce electricity, then alternate generating capacity additions should serve as the appropriate alternate. If the major goal is to back out foreign oil, then the cost of conservation should be considered. The Corps of Engineers has used both the cost of nuclear and oil fired capacity as the true alternate cost with oil generally serving as the most appropriate alternative.

C. Panel Discussion.

Philip Hastings - Hydro development may displace peaking capacity.

Charles Colgan - 'Alternatives which meet the same goal should be compared. Also, alternatives should be technically comparable. As an example, a 5 megawatt hydro plant cannot be equated to a 1100 megawatt nuclear plant. Petroleum based alternatives are reasonable to judge a hydro project.

William Beardsley - Noted that one has to consider all possible options together and not in isolation. For example, the cost of a hydro project should be compared with such options as conservation, windmills, etc.

Gary Dawbin - The appropriate alternative should not be nuclear plants or combined cycle units but should be the cost of backing out oil.

Bill Shipman - The appropriate measure of an alternative is the cost of energy from the next best alternative. As such, one has to look at a range of substitutes. Alternative could be the incremental electricity produced compared to hydro produced energy. The next best alternative may be more difficult the longer out one looks. For example, the 100-year lifespan of a tidal project could encompass the life of three thermal plants. The only alternative that needs to be measured is the cost of electricity itself since capacity is not dependable. He feels the real alternative is electricity generated by OPEC oil, not nuclear. Comparison should be made with alternatives with similar capacity and output, if possible.

III. A. How should externalities be accounted for?

B. In many cases, particularly in energy production and consumption, externalities or spillover effects can occur which are difficult to measure, but nevertheless, should have important effects in translating the correct market signals. Examples of externalities which should be accounted for in the example of hydropower production and comparision with alternatives are the following:

1. Pollution effects resulting from coal or oil use in generating electricity.
2. Environmental and health effects associated with radiation from nuclear plants, nuclear waste disposal and decommissioning.
3. Accounting for the economic cost of foreign oil on balance of payments deficits, inflation, unemployment, national security, etc.

These are examples of externalities associated with the production of alternatives which should be accounted for but are difficult to measure and internalize. However, they should enter the equation in one form or another to determine the true economics of alternative projects.

C. Panel Discussion.

Charlie Colgan - Noted two unpriced externalities associated with both alternatives:

1. Environmental effects.

2. Efficient use of energy resources. As an example, the thermal efficiency of oil plants creates a scarcity rent or loss to society as a result of efficiency losses.

William Beardsley - Noted that the goal of society is to allocate resources so that the marginal social benefits are equal to the marginal social costs, or in comparing two or more alternatives, the marginal social benefit of A divided be the marginal social cost of A equals the marginal social benefit of B divided by the marginal social cost of B. Because of external economics and diseconomies, these ratios may not be equated. Relative price shift analysis must account for external and internal economies and diseconomies.

Gary Dawbin - Also suggested that externalities be included in evaluation procedures.

IV. A. What is the appropriate time frome for analysis of the economic benefits and costs of a hydro project?

B. The life span of a hydro project is generally assumed to be 100 years, while an alternate oil-fired plant may be only 35 years. Whether benefits and costs of a hydro facility are measured over the entire 100 year time horizon or over the life of an alternate facility will affect the relative economics of the alternatives.

C. Panel Discussion.

William Beardsley - Time frame of 100 years for a combined cycle unit is unrealistic because of future technology.

General tone of discussion is that after comparison with one plant with a life of 35 years or so, estimating costs become more and more difficult

V. A. How do we account for future technologies?

B. Since no one has any idea concerning the costs and scope of future technologies, once the 35-year time horizon is exceeded, the cost of the alternative becomes impossible to determine since that alternative could be some new technology which has yet to be proven. This problem adds to the uncertainty involved in calculating all future benefits and costs.

C. Panel Discussion.

William Beardsley - Relative price shift analysis makes more sense in the short run than in the long run, because of the uncertainty of future technology over a 100-year period.

Myrick Freeman - One of the major problems involved in calculating benefits and costs is the estimation of new technologies.

William Shipman - Trying to predict technology and its impact on cost is difficult.

VI. A. How do we account for the problems of estimating future benefit and cost components such as fuel prices?

B. One of the primary requirements of relative price shift analysis is the need to estimate all the benefits and cost components over the life of the project. Future estimates of such variables as oil prices are going to be fraught with errors. The question is, is this approach to benefit-cost analysis superior to static benefit-cost analysis given estimation are possible?

C. Panel Discussion.

Charles Colgan - Norman Laberge and Rick Freeman addressed this issue as one of importance, but also stressed the problems involved in providing future estimated projections of different variables. One advantage of relative price shift analysis is that relative and not absolute cost changes are important. Thus, relative changes may be easier to predict than absolute changes and errors can be minimized.

Gary Dawbin - The degree of risk for various parameter estimates in relative price shift analysis should be simulated.

VII. A. Should ancillary benefits be included?

B. If ancillary benefits can be measured, there is no doubt they should be included in a cost-benefit analysis. Ancillary benefits or others who benefit besides project beneficiaries resulting from a hydro project could be a recreational area for boating and swimming, increased employment benefits in the area, etc. Since all these benefits, and possible ancillary costs result from the project, they should all be included if they can be measured. Perhaps revenue generated from these activities or income generated could serve as a measure of benefits.

C. Panel Discussion.

Professor Hines - Noted that the inclusion of ancillary benefits could raise the benefit-cost ratio above one in many cases. He cited two ancillary benefits associated with the Dickey-Lincoln Project:

1. Downstream development and recreational opportunities.

2. Economic redevelopment benefits for the area involved in terms of increased employment creation.

The feeling was also generated in open discussion that continued reliance on foreign oil leads to loss of jobs, income and higher prices while hydro development will soften the impact.

Perhaps, the economic benefits of backing out foreign oil should be measured and included. Both Gary Dawbin and William Beardsley made the point that employment benefits to Maine as a result of hydro development, both direct and indirect should be internalized in any benefit stream.

VIII. A. How does the question of variable power reliability effect utility planning?

B. Hydropower development is unique in that power cannot be generted constantly. In the case of tidal power, reliable power will only be available during periods of high tides. Other hydropower developed will also have variable power reliability such as during a spring runoff. Many times, hydropower is used for pumped storage purposes and released during peak power needs. But many times, pumped storage requires more energy as input than is released as output. The cost of variable power reliability as well as the ability to incorporate hydro development in the generation expansion plans of the utility system is most important.

C. Panel Discussion.

Philip Hastings - The objectives of power generation expansion planning is to minimize the cost of energy to consumers over the planning horizon. The impact of a hydro project should include the impact on all generating units over the life of the project. In other words, in analyzing the benefits and costs of a hydro project, utility planners must analyze what capacity the hydro project will displace as well as the costs of that capacity. To fully evaluate hydro projects, the impact of the development over the life of the project should be considered along with the generating expansion plans of the utility.

IX. A. Should one definitive benefit-cost ratio be used or would setting up a confidence interval of benefits and costs be more appropriate?

B. Given the possible estimation problems involved in calculating future benefit and cost components as well as uncertainty of the appropriate discount rate, one definitive benefit-cost ratio is extremely tenuous. Only a range of benefit-cost ratios under various assumptions could best provide an indication of the benefit-cost ratios possible.

C. Panel Discussion.

Myrick Freeman - Uncertainty in calculating relative prices could be accounted for by setting up confidence interval estimates or other probability analysis.

X. A. Is relative price shift analysis a more effective way of measuring benefits and costs?

B. Relative price shift analysis is an attempt to more accurately account for the change in the value of benefit-cost parameters over time as opposed to traditional static benefit-cost analysis which assumes the future will be the same as today.

C. Panel Discussion.

Everyone agreed that relative price shift analysis is an improvement over present techniques and is a step in the right direction, because this technique considers the dynamic changes in components of benefits and costs over the life of the project. However, one viewpoint which was introduced is that relative price shift analysis biases benefits upward. But is this the case or does static benefit-cost analysis bias costs upward over time?

ATTENDEES NOT ON PROGRAM

Symposium on Relative Price Shift Analysis
NOVEMBER 27, 1979

R. L. Bean
Central Maine Power Co.

Dr. Richard Burns
EPA - Boston

R. V. Clark
Eastern Maine Electric Cooperative

F. A. Durgin
University of Southern Maine

Judy Kany
Maine Legislature

T. Mark Kraczkiewicz
Charles T. Main, Inc.

Charles Lawton
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Arthur Lerman
Lerman Associates

Russell Libby
National Center for Economic Alternatives

Robert C. McMahon
University of Southern Maine

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Donovan A. Robertson
Central Maine Power Co.

Frank Sleeper
Portland Press Herald

T. R. Snyder
St. Francis College

Greg Stevens
Senator William Cohen's Office

Carl E. Veazie
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Larry L. Wilkerson
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Federal Energy Regulatory Commission

William E. Knight
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William H. Beardsley

Education:	Ph.D., Department of Geography and Environmental Engineering, Johns Hopkins University B.A., Department of Economics, Earlham College Other: McGill, Harvard, University of East Africa
Employment:	Assistant to the President, Bangor Hydro-Electric Company Former employment includes aide to Vermont Governor Deane C. Davis, Assistant Professor of Geography and Assistant to the Dean at the University of Vermont, and Staff to the Royal Commission on the Economic Prospects of Newfoundland and Labrador.
Publications:	(selected) Journal of Forestry, Pulp and Paper Magazine of Canada, Northern Logger, Yankee, Proceedings of the Institute of Gas Technology, Proceedings of the Vermont Academy of Arts and Schiences, and the Journal of the Northeastern Agricultural Economics Council, on energy, environmental, and socio-economic subjects.
Activities:	Vice Chairman of the Conservation Committee, New England Energy Congress; past Chairman of Load Management Committee of the Electric Council of New England; alternate member to the NEPOOL Management Committee, past member of Vermont Governor's Task Force on Wood as a Source of Energy; and Society of Xi.
Personal:	Age - 37; Married - Wife and three children; Home - Orono, Maine

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EMPLOYMENT

1977-Present: Senior Planner, Economic Planning and Statistical Services Division, Maine State Planning Office (184 State St. Augusta, Maine 94333)

Coordinator of all planning and policy development relating to offshore oil development. Program Manager for Maine of the Coastal Energy Impact Program. Economist performing a variety of economic analyses for the Governor and Legislature on matters relating to energy, natural resources, and regional economics. Economist assigned to Maine Department of Transportation for port planning. Governor's Science Advisor.

1976-1977: Planning Analyst, Economic Planning and Analysis Division, Maine State Planning Office

Research and analysis of offshore oil policy and planning questions. Policy analysis on industrial siting.

1976: Lecturer in Political Science, Muhleberg College, Allentown, Pennsylvania (18104)

Taught three courses: Introduction to Political Science
International Politics
International Law
(12 Semester Hours)

Supervised Model United Nations Program

1973-1974: Librarian, Anspach Institute for Diplomacy and Foreign Affairs (University of Pennsylvania)

Supervised and managed operations in social science library, including purchasing, circulation, cataloguing.

EDUCATION

Ph.D. (pending) in International Relations, University of Pennsylvania, Philadelphia, Pennsylvania 19174.

Dissertation Title: The Economic Foundations of International Ocean Resource Management

B.A. (1971) in History, Colby College, Waterville, Maine 04901

Areas of Specialization:
- Resource and Energy Economics
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HONORS AND AWARDS:

Charles A. Dana Scholar (1969-1970)
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President, International Relations Graduate Students Association (1972-1973)

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PUBLICATIONS:

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______________, and Fries, Sylvia D., et. al., Science in the Statehouse: Alternative Channels of Technical Information for Decision Makers in Maine Government. (1979, Orono, Maine) Social Science Reserach Institute.

Personal Data of

GERALD G. DAWBIN

Born and raised in Maine, a native of the Augusta Area.

Educated in Augusta Schools, but graduated from Searsport High School in 1959.

Post-Secondary Education:

Colby College, 1960-1962. Majored in Physics

Graduated Wentworth Institute, 1964, with Associate Degree in Aeronautical and Space Engineering Technology.

Graduated University of Southern Maine, 1974, BS in Business Administration.

Work Experience:

1964-1967: General Electric Company, Schenectady, New York, working on the design, manufacture and installation of large steam turbine-generators for central power stations.

1967-1976: Central Maine Power Company, Augusta, Maine, working on various phases of electric utility power plant operation and maintenance.

1976-present: Office of Energy Resources, Augusta, Maine, principal author and organizer of the 1976 Maine Comprehensive Energy Plan, and involved in various aspects of energy planning, primarily renewable resource development, specializing in hydropower, tidal power and wind energy projects.

A. Myrick Freeman III

VITA

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Present Position: Professor of Economics, Bowdoin College

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Degrees: A.B., Cornell University, 1957
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Fellowships: Resources for the Futures, Inc., Doctoral Dissertation Fellowship, 1964-65

Thesis: The Federal Reclamation Program and the Distribution of Income. Submitted: December 1965

Major Fields of Interest:

1) Economics of Environmental Quality
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Past Positions Held:

1976-78	Fellow, Resources for the Future, Inc. Washington, D. C.
1973-75	Associate Professor of Economics and Chairman, Department of Economics, Bowdoin College
1973	Visiting Associate Professor, University of Wisconsin, Madison, Wisconsin, Spring Semester
1971-72	Associate Professor of Economics and Chairman. Department of Economics, Bowdoin College
1969-70	Visiting Scholar, Resources for the Future, Inc., Washington, D. C.
1965-69	Assistant Professor, Department of Economics, Bowdoin College
1964-65	Doctoral Dissertation Fellow, University of Washington (Grant from Resources for the Future, Inc.)

1963-64	Research Associate and Predoctoral Associate, Department of Economics, University of Washington, Seattle, Washington
1957-63	Naval Service--including Assistant Professor of Naval Science at the University of Washington, Seattle, Washington

Books:

1. International Trade: An Introduction to Method and Theory, New York, Harper & Row, 1971
2. The Economics of Environmental Policy, with Robert H. Haveman and Allen V. Kneese, New York, John Wiley, 1973.
3. Pollution, Resources, and the Environment--A Book of Readings, with Alain C. Enthoven, New York: W. W. Norton and Co., 1973
4. The Benefits of Environmental Improvement: Theory and Practice, Baltimore: Johns Hopkins University Press, 1979.

Prepared Testimony:

1. U.S. House of Representatives, Committee on Ways and Means, Tax Recommendations of the President--the Lead Tax, September 16, 1970
2. U.S. Senate, Committee on Interior and Insular Affairs, Trans-Alaskan Pipeline, May 3, 1973
3. U.S. House of Representatives, Committee on Interior and Insular Affairs, Subcommittee on Public Lands, Trans-Alaskan Pipeline, May 17, 1973
4. U.S. Senate, Committee on Public Works, Water Resources Subcommittee, Benefit-Cost Analysis, June 27, 1974

PHILIP C. HASTINGS

EDUCATION:

BSEE, 1970, Northeastern University (Cum Laude)
MSEE, 1971, Northeastern Universtiy

EXPERIENCE:

Since 1975, Mr. Hastings has been responsible for all corporate research activities at Central Maine Power Company. His areas of involvement include energy conservation and load management, co-generation solar, wood, wind, and hydro as well as nuclear and coal. Efforts in these areas include technical and economic assessment, supervision of research activities, and evaluation of impact on future energy supply.

From 1971 to 1975, Mr. Hastings served as a planning engineer with particular responsibility for generation planning. His activities included development of long range generation expansion plans, review of short range capacity alternatives and development and assessment of economic tools for evaluation of energy supply alternatives.

Mr. Hastings is a registered professional engineer and a member of several energy related groups including: the New England Solar Energy Association, the Solar Energy Industries Association, the American Wind Energy Association, the Regional Resources Committee of the Northeast Solar Energy Center, the Research Task Force of the Electric Council of New England and the Load Managerment Working Group of the New England Power Pool.

Lawrence G. Hines

Biography

Born: October 31, 1915; married. one child.

A.B., University of Kansas. 1938; A.M., University of Minnesota, 1942;
Ph.D., University of Minnesota, 1947

Regular Employment

Instructor and Assistant Professor, University of Minnesota, 1942-46;
Air Intelligence Specialist, Office of Naval Intelligence assigned to Joint Army-Navy Intelligence Division, Washington, D.C. 1946-47;
Assistant Professor, Dartmouth College, 1947-52; Professor, Dartmouth, 1952- ; 1960-63. Chairman of the Division of the Social Sciences; 1963-65, Chairman of the Department of Economics; Associate Chairman, 1978-.

Consulting Employment

Water Pollution Control Division, U.S. Public Health Service, H.E.W. Department, Washington, D.C., 1956-63. Economic consultant for the Water Pollution Control Division involved various tasks including serving on the staff and Subcommittee on Evaluation Standards in the revision of the Report to the Interagency Committee on Water Resources, Proposed Practices for Economic Analysis of River Basin Projects ("Green Book" revision, May 1958), and Project Officer for two research contracts with the University of Chicago and Stanford University for the development of techniques of benefit-cost analysis appropriate for use in evaluating water pollution control projects.

Office of Economics, Department of Transportation, Washington, D.C., 1967-68.
Institute of Public Administration, New York, in water research 1970-72;
Department of the Interior, Washington, D.C., 1974.

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Articles

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Environmental Issues (New York: W.W. Norton, 1973).

The Persuasion of Price (Cambridge, Mass.: Winthrop Publishers, 1977).

Economics and the Environment (forthcoming).

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Education

Ph.D. - Materials Science (Minor-Physics), Catholic University of America, Dept. of Chemical Engineering and Materials Science, Washington, D.C.

M.S.E. - Solid Mechanics, Catholic University, Mechanics Department

B.C.E. - Civil Engineering, Catholic University. Dept, of Civil Engineering.

Dissertation

Topic; "Study of the Mechanics of Stress Relaxation in Vitreous Systems"

Experience & Background

1. Laboratory Research Assistant; employed while a graduate student in Mechanics Dept. and later in the Materials Science Dept. Ultrasonic measurements and stress relaxation studies were later added in conjunction with work required for my dissertation research.

2. Post-Doctoral Research Associate - Vitreous State Lab, Catholic University. Responsible for the preparation of High-grade glass fibers for use in long-range transmission lines.

3. Director of Passamaquoddy Tribe's Energy Office, Pleasant Point Reservation, Perry, Maine. Specific areas of responsibility:

- preparation of an appraisal report dealing with the construction of a demonstration tidal power plant,

- design of a research facility with solar and wind elements incorporated into its structure,

- submittal of proposals for project funding,

- investigation of tidal power research topics.

This work involved Federal, State, and private industry interaction; staff supervision; project implementation: and data collection and analysis.

PUBLICATIONS

1. "Inadequacies of Viscosity Theories for a Vitreous Alkali-Nitrate Melt". H. Tweer, N. Laberge, P.B. Macedo, Journal of American Ceramic Society, 54 (2), 121-123,

2. "Stress and Strain Relaxation in Two Soda-Lime-Silicate Glasses", N. Laberge, P.B. Macedo, G.L. Madan, and C.J. Montrose, Paper presented at the American Ceramic Society meeting, Chicago, 1972.

3. "Ultrasonic Study of High Frequency Velocity in Silicate Glasses", N. Laberge, C. Montrose, V. Vasilescu, P.B. Macedo. Paper presented at the American Ceramic Society Meeting, Washington, D.C.

4. "Equilibrium Compressibilities and Density Fluctuations in K_2O-SiO_2 Glasses", N. Laberge, P.K. Gupta, V. Vasilescu, P.B. Macedo, Journal of Non-Crystalline Solids (1975)

5. "Decay Function for the Electric Field Relaxation in Vitreous Ionic Conductors", C.T. Moynihan, L. Boesch, N. Laberge. Physics and Chemistry of Glasses, Vol. 14, 6 (Dec. 1973), pg. 122-125.

6. "Scattering Losses in Binary Borate Glasses", N.Laberge, P.K. Gupta, V. Vasilescu, P.B. Macedo, Journal of Non-Crystalline Solids, 13 (1973.1974), 164-72.

REPORTS

1. Technical Reports:

    No. 1 - Computer Algorithm for Tidal Power Calculations
    No. 2 - Tidal Plant Simulation for Half-Moon Cove
    No. 3 - Continuous Energy Production from Linked Basins
    No. 4 - Economic Analysis of Tidal Power Plants in Cobscook Bay
    No. 5 - Environmental Effects of Tidal Power Plants
    No. 6 - Power Markets: Interaction with Tidal Power Plants
    No. 7 - Research and Development Objectives: Half-Moon Cove Tidal Projects

2. Discussion Papers

    No. 1 - Intervational Two-Pool Tidal Power Project: Review and Analysis
    No. 2 - Economic Analyses of Half-Moon Cove Tidal Projects
    No. 3 - Small vs. Large Tidal Power Plants
    No. 5 - Computer Simulation Study: Assessment of Performance Criteria

3. Life Cycle Cost Analysis: Half-Moon Cove Tidal Project

4. Research Reports:

    No. 2 - Life Cycle Economic Justification for Tidal Power Plants
    No. 3 - Tidal Power Integration into the Regional Electrical Network: Supply and Demand
    No. 4 - Research and Development Benefits of Demonstration Project

WILLIAM D. SHIPMAN

Bowdoin College
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Positions:

Inst., Ass't., Assoc.. Professor, Bowdoin College 1957- ; Chairman 1967-; Adams-Catlin Professor of Economics 1969-

Investment Analyst, Brown Brothers Harriman & Co., New York, New York 1953-1957

Price Economist, U.S. Office of Price Stabilization, Seattle, Washington 1951-1952

Academic Background:

Ph.D. Columbia University, 1960 (in residence 1953-1957)
M.A. Univ. of California (Berkeley), 1950
A.B. Univ. of Washington, 1949

Research:

An Inquiry into the High Cost of Electricity in New England, Wesleyan University Press, 1962

"Some Economic Implications of Nuclear Power Generation in Large Central Stations," Land Economics, February 1964

"Alternative Proposals for Electric Power Development in Maine," Research report prepared for and published by the Federal Reserve Bank of Boston, 1964

"The Impact of Nuclear Power in New England." Journal of Industrial Economics, November 1965

Road-Rail Competition and British Transport Policy, unpublished monograph, Dept. of Applied Economics Library, Cambridge, England 1967

"Rail Passenger Subsidies and Benefit-Cost Considerations." Journal of Transport Economics and Policy, January 1971

An Energy Policy for the State of Maine, (with Carl E. Veazie), Bowdoin Public Affairs Research Center, 1973

Personal:

Born 1925 in Glen Ellyn, Illinois. Attended primary and secondary schools in that town

Married 1955 . . . . .two children

Other:

Brookings Research Professorship, 1962-1963 (nuclear power)

Visitor to University of Cambridge, Department of Applied Economics 1966-1967(British transport)

Chairman, Brunswick Planning Board 1961-1963

Trustee, Brunswick Savings Institution 1965-1977

Other:

Sometime chairman of various college committees including curriculum, admissions, and advanced study

Consultant, New England Regional Commission 1968-

Consultant, Maine Public Utilities Commission 1975-

Member, Governor's Task Force on Energy and Heavy Industry on the Maine Coast, 1972

Member, Governor's Study Committee on Dickey-Lincoln Project 1977

BOWDOIN COLLEGE

DEPARTMENT OF ECONOMICS BRUNSWICK, MAINE 04011

January 28, 1980

Dr. Normand Laberge
Half Moon Cove Tidal Power Project
P.O. Box 203
Eastport, Maine 04631

Dear Normand:

I told you at the Portland meeting on November 27 that I had some reservations about your analysis of relative price shifts. I apologize for not getting back to you sooner, but I've been pressed to finish a couple of other projects. I've just been going over your paper, and I believe that your treatment of "fixed charges" in Appendix I is in error.

For the moment, let me focus on the stream of costs associated with the construction of a tidal project.

Let C_o = construction costs

C_{1t} = operation, maintenance, and replacement costs incurred in year t -- assuming no inflation

C_{2t} = "fixed charge" in year t -- assuming no inflation

r = real rate of return -- the discount rate used for benefit cost analysis -- assuming no inflation

i = annual inflation rate -- constant

d = discount rate incorporating inflationary premiums

= r + i + r·i

The project has a life of T years. Assuming no inflation, Co and C_{1t} are actual costs incurred on the dates given by the subscripts. For simplicity, assume that C_{1t} is the same for all t. The present value of this stream of costs is:

(1) $$PV_c = C_o + \sum_{t=1}^{T} \frac{C_{1t}}{(1+r)^t}$$

It is sometimes convenient to compute the annual equivalent (AE) of this stream as follows:

(2) $$C_{2t} = C_0 \frac{r(1+r)^T}{(1+r)^T - 1}$$

(3) $$AE_c = C_{1t} + C_{2t}$$

Of course, we must have:

(4) $$PV_c = \sum_{t=1}^{T} \frac{AE_c}{(1+r)^t} = \sum_{t=1}^{T} \frac{C_{1t}}{(1+r)^t} + \sum_{t=1}^{T} \frac{C_{2t}}{(1+r)^t}$$

It is this consistency requirement which is violated by the way you handle the inflation factor with C_{2t} as an equivalent to Co.

Let there now be inflation. It affects only the C_{1t} of (1). We could compute,

(1') $$PV_c' = C_0 + \sum_{t=1}^{T} \frac{C_{1t}(1+i)^t}{(1+d)^t}$$
$$= C_0 + \sum_{t=1}^{T} \frac{C_{1t}(1+i)^t}{(1+r)^t(1+i)^t}$$

and we get the standard result that PV'c = PVc, In (A.7) of Appendix I, you propose to compute a sequence of annual costs incorporating inflation as follows:

(5) $$C_t(1+i)^t = \left[C_{1t} + C_{2t}/(1+i)^t\right](1+i)^t$$

For this to be correct and consistent with the underlying true cost stream, we must have:

(6) $$PV_c'' = \sum_{t=1}^{T} \frac{C_t(1+i)^t}{(1+d)^t} = PV_c$$

But substituting (5) into (6) gives:

(7) $$PV_c'' = \sum_{t=1}^{T} \frac{C_{1t}(1+i)^t}{(1+r)^t(1+i)^t} + \sum_{t=1}^{T} \frac{\left[C_{2t}/(1+i)^t\right](1+i)^t}{(1+r)^t(1+i)^t}$$

As you can see $PV_c'' < PV_c$. Equation (6) holds only if you apply the inflation factor $(1 + i)^t$ to the fixed charge component of annual equivalent costs. The same line of reasoning applies to your analysis of benefits and your equations in Appendix II.

I'd appreciate your reaction to these comments.

Sincerely yours,

Rick Freeman

A. Myrick Freeman III
Professor of Economics

cc: Prof. Arthur Johnson
Dr. John Joseph
Colonel Max. B. Scheider

February 19, 1980

Dr. A. Myrick Freeman III
Bowdoin College
Department of Economics
Brunswick, Maine

Dear Dr. Myrick;

Thank you for taking the time to respond to the paper that I presented at the relative price shift analysis conference held on November 27. I have prepared a number of comments in defense of my methodology and have also presented further justification for the approach outlined in my report.

Before proceeding with a discussion of the present value formulation, I would like to point out that the primary thrust of my paper was aimed at the relative price shift analysis performed by the Corps of Engineers for the Cobscook Bay tidal power project. I contended that their analysis assumed the absence of inflation which drastically affected the results. In this case, the inclusion of a realistic inflation rate would have produced a more favorable view of the long-term benefits of tidal power.

I will use the same notation that appears in your letter of January 28. For the case of no inflation, we then have;

$$PV_c' = \sum_{j=1}^{2}\left(\sum_{t=0}^{T} C_{jt}/(1+r)^t\right) \qquad (1)$$

Similarly, with inflation;

$$PV_c'' = \sum_{j=1}^{2}\left(\sum_{t=0}^{T} \frac{C_{jt}(1+i)^t}{(1+d)^t}\right. \qquad (2)$$

You assumed that C_{1t} is the same for all t, which is also true for C_{2t} by definition for this example. Therefore;

$$PV_c'' = \sum_{j=1}^{2} C_{jt}\left(\sum_{t=0}^{T}\frac{(1+i)^t}{(1+i)^t(1+r)^t}\right) \qquad (3)$$

By observation, $PV_c' \equiv PV_c''$. My presentation assumed that during the first year of operation ($t = 0$) we would have;

$$\sum_{j=1}^{2} C_{j0} = C_{10} + C_{20} \qquad (4)$$

However, in order to incorporate the effect of inflation, I then used the following equation;

$$\sum_{j=1}^{t} C_{jt} = C_{1t} + C_{2t}/(1+i)^t \qquad (5)$$

By comparison, eqn.5 does not agree with eqn.3; i.e., t-dependence of C_{jt} expressed in eqn.5 is outside the time summation. By substituting eqn.5 into eqn.2, we arrive at your "eqn.5" which proves that $PV_c' \neq PV_c''$ for the case presented in my paper. I hope that this derivation adequately summarizes your conclusion.

In order that $PV_c' = PV_c''$, we can then say that;

$$PV_c'' = \sum_{j=1}^{2}\left(\sum_{t=0}^{T} C_{jt}\frac{(1+i)^t}{(1+d)^t}\right) \tag{6-a}$$

$$= \sum_{t=0}^{T}\frac{C_{1t}(1+i)^t}{(1+r)^t(1+i)^t} + \sum_{t=0}^{T}\frac{C_{2t}(1+i)^t}{(1+r)^t(1+i)^t} \tag{6-b}$$

$$= \sum_{t=0}^{T}\frac{C_{1t}}{(1+r)^t} + \sum_{t=0}^{T}\frac{C_{2t}}{(1+r)^t} \tag{6-c}$$

IN EQN.(6-C)

where $\boxed{C_{1t} \text{ and } C_{2t}}$ are expressed in terms of first year of operation dollars ($t=0$). However, eqn.(6-b) should theoretically give the same results for current dollars. But C_{2t} remains constant during the project's economic lifetime and is therefore not affected by the rate of inflation. I pose two questions;

1. Is the generalized eqn.(6-a) capable of seperating two discount rates - an inflation controlled rate and a time determined discount rate ?

$$\left(\sum_{t=0}^{T} C_{2t}/(1+d)^t\right) \text{ OR } \left(\sum_{t=0}^{T} C_{2t}/(1+r)^t\right)$$

2. Is the equation, $PV_c' = PV_c''$, a necessary requirement for the calculation of an underlying true cost stream ?

In my opinion, the problem or contradiction lies in the general definition of the present value. By factoring out the effect of inflation with the conditon that $PV_c' = PV_c''$, we are not analyzing the impact that inflation would have on a project such as a tidal power plant which is highly capital intensive and not dependent on a market-controlled fuel source. In summary, the requirement that $PV_c' = PV_c''$ places a restriction on the methodology that mathematically ignores inflation. Present value should compare the value of a tidal project with respect to discount rates that would be in effect during a certain year; i.e., $C_{2t}/(1+d)^t$.

If the present value calculations are formulated in a manner which excludes the consideration of inflation, what method should then be used to properly illustrate the impacts of inflation. Life cycle cost analysis and relative price shift analysis provide methods to understand the impacts of inflation on project economics. However, according to my paper relative shift analysis has to state an inflation rate in order to properly interpret the results.

The simplified model used in my calculation of a time-dependent benefit-to-cost ratio was based on the equations that appear on page 13 (Section B) of my paper. Two equations are specified - before plant operation (case 1) and post-construction conditions (case 2). Consider the post-construction equation for the B-C ratio. In this case, the inflation term, $1/(1+I)^i$, does not cancel out due to the presence of two fixed charge components, B_2 and C_2. The following equation was used for the calculation of the BC ration;

$$(BCR)_i = \frac{\left(B_1(1+f)^i + \frac{B_2}{(1+I)^i} + B_3\right)(1+I)^i}{\left(C_1 + \frac{C_2}{(1+I)^i} + C_3\right)(1+I)^i} \tag{7}$$

where, B_i and C_i were expressed in terms of the construction period costs and i was the index prepresenting the number of years after the completion of construction. Obviously, the results would be much different for the case of inflation as compared to a zero rate of inflation. This formulation, in my opinion, properly considers the effects of inflation and fuel cost escalation in a manner which realistically portrays the expected deficits/benefits of a tidal power project when compared to another form of production. It also describes the behavior in a more easily comprehendable way.

It might be beneficial to discuss these differences at a blackboard instead of through the mail. I would appreciate your comments.

Sincerely,

Normand Laberge

Normand Laberge

cc: Prof. Arthur Johnson
Dr. John Joseph
Colonel Max. B. Scheider

BOWDOIN COLLEGE

DEPARTMENT OF ECONOMICS **BRUNSWICK, MAINE 04011**

March 3, 1980

Dr. Normand Laberge
Half Moon Cove Tidal Power Project
P.O. Box 203
Eastport, Maine 04631

Dear Normand:

Thank you for your response to my letter. Your question #2 on the second page gets to the heart of the matter. Stripped of all the algebra, the issue is whether the present values of the cost streams computed in different ways must all be equal ($PV_c = PV_c' = PV_c''$). The answer is yes.

The point to remember is that what you call "Fixed charges" or C_{2t} does not represent an acutal outlay, but rather is an accounting artifact, an annual equivalent to the true capital outlay in period t = 0. The fixed charge must be computed in a manner consistent with the other assumptions of the analysis, that is, so that the present values of the accounting cost stream [Equation (4) and (6) of my letter] are equal to the present values of the true cost streams [Equations (1) and (1') of my letter].

I believe that you computed the fixed chanrge C_{2t} using the real rate of return according to:

(a) $$C_{2t} = C_0 \frac{r(1+r)^T}{(1+r)^T-1}$$

This is consistent with my Equation (4) in the no inflation case. With inflation, the present value of the true cost stream is:

(1') $$PV_c' = C_0 + \sum_{t=1}^{T} \frac{C_{1t}(1+i)^t}{(1+d)^t}$$

$$= C_0 + \sum_{t=1}^{T} \frac{C_{1t}(1+i)^t}{(1+r)^t(1+i)^t}$$

If instead you use the fixed charge, i.e., the annual equivalent of C_o computed according to (a) to represent the cost stream, its present value (PV_c'') must equal the present value of the true cost stream (PV_c'). This requires that you represent the cost stream as:

$$\text{(b)} \qquad C_t(1+i)^t = C_{1t}(1+i)^t + C_{2t}(1+i)^t$$

rather than as you did it:

$$\text{(c)} \qquad C_t(1+i)^t = C_{1t}(1+i)^t + C_{2t}$$

The present value of the accounting stream of annual costs (b) is:

$$PV_c'' = \sum_{t=1}^{T} \frac{(C_{1t} + C_{2t})(1+i)^t}{(1+r)^t(1+i)^t}$$

$$= \sum_{t=1}^{T} \frac{c_{1t}(1+i)^t}{(1+r)^t(1+i)^t} + \sum_{t=1}^{T} \frac{c_{2t}(1+i)^t}{(1+r)^t(1+i)^t}$$

which is equal to Equation (1') above since

$$\sum_{t=1}^{T} \frac{c_{2t}}{(1+r)^t} = C_o$$

Alternatively, if you had calculated the fixed charge using the nominal interest rate d, then your approach to treating inflation would be correct.

$$\text{(d)} \qquad \hat{C}_{2t} = C_o \frac{d(1+d)^T}{(1+d)^T - 1}$$

and $$C_t(1+i)^t = \left[C_{1t} + \hat{C}_{2t}/(1+i)^t\right](1+i)^t$$

$$= C_{1t}(1+i)^t + \hat{C}_{2t}$$

and $$PV_c' = \sum_{t=1}^{T} \frac{c_{1t}(1+i)^t}{(1+d)^t} + \sum \frac{\hat{C}_{2t}}{(1+d)^t}$$

This is because according to (d), the second term above is equal to C_o.

I hope that this clarifies the situation. If you have plans to be in the Portland area, let me know; and perhaps we can plan to get together.

Sincerely yours,

Rick Freeman

A. Myrick Freeman III
Professor of Economics

cc: Prof. Arthur Johnson
Dr. John Joseph
Colonel Max. B. Scheider

P.O. Box 151
Eastport, Maine

March 15, 1980

Dr. A. Myrick Freeman III
Bowdoin College
Department of Economics
Brunswick, Maine

Dear Myrick:

Your last letter was very useful in pinpointing the differences between the approaches used in the calculation of present value. Exhibit "A" lists the various equations referenced in your letter and in my paper. The critical expression is the one which calculates C_{2t} and $\hat{C}_{2t}$ based on the formulation of $C_t(1+i)^t$. I agree with this representation, but it still doesn't adequately reflect the impact of inflation, a topic which will be discussed later.

I then used the equations from Exhbit "A" to prepare Table 1. Several comments are appropriate from this analysis, namely:

- sum of $C_{2t}/(1+r)^t$ and $\hat{C}_{2t}/(1+d)^t$ both equal C_0 which agrees with the requirements imposed by eqns. 7 (ex.A)

- $\hat{C}_{2t}$ is not equal to C_{2t} which results in a higher total payment for the so-called Laberge versus Freeman approach; i.e., 1.639 C_0 vs. 1.490 C_0 over the theoretical ten year period

- behavior of $C_{2t}/(1+r)^t$ versus time and $\hat{C}_{2t}/(1+d)^t$ versus time are quite different (Figure 1) even though the respective sums are equal to unity

- Figure 1 illustrates a different dynamic behavior indicative of an underlying difference in the development of a simplified economic model

In order to understand the differences, it might help to ask the following question --- Should the annual fixed cost be equal to 0.1490 C_0 or 0.1639 C_0 ? Also, should the differences mentioned above be considered as important concerns ? These points will be addressed later.

Table 2 was prepared in a similar way except for the inclusion of a different inflation rate during the second year. The equations listed in Exhibit "A" were followed in their true mathematical sense. In this example, the observations are noted below:

- the Freeman method, so-called, remains the same even with the higher rate of inflation after the first year since C_{2t} is calculated on the basis of the conditions stated

With regards to Table 2, it was assumed that the term $\hat{C}_{2t}/(1+d)^t$ was calculated with the following dependence;

$$\hat{C}_{2t}/(1 + d(t))^t$$

where the discount rate, d(t), was re-evaluated for each respective year in accordance with equation 9 (exhibit "A"). Therefore, with a new inflation rate for the second year a different discount rate was calculated for this example. This change caused the following result;

$$\sum \hat{C}_{2t}/(1 + d(t))^t < 1$$

which contradicts the hypothesis. What does this result actually infer with regards to the calculation of present value ? In my opinion, it does represent a realistic situation under a process which might be called "relative inflation behavior". Assuming that the term "present value" reflects the value of an investment made x number of years earlier, it then seems logical to assume that a higher inflation rate will decrease the present value of that investiment in year "x" reflected by a correspondingly decreased value for the discount rate; i.e., d(t).

The so-called Laberge methodology was derived on the intuitive basis that:

$$C_t(1 + i)^t = C_{1t}(1 + i)^t + \hat{C}_{2t}$$

This expression says that the fixed charge component is independent of inflation as stated in current dollars. In my opinion, this formula is correct since it represents $\hat{C}_{2t}$ as a cost established by the conditions that exists during the first year and which will remain constant throughout the project's economic lifetime.

I would like to once again express my main thesis which only peripherally relates to the topic of present value. The benefit-to-cost ration calculated as a function of time represents the actual conditions observed in practice without the inclusion of the factors $(1+r)^{-t}$ and $(1+d)^{-t}$. Page 13 of my paper lists the equations used for this analysis. The major conclusion of that paper noted that the relative price shift analysis performed by the Corps of Engineers assumed an inflation rate of ZERO which should have been clearly stated at the beginning of their report.

I feel it would be extremely useful to meet in person to discuss this and other topics. It seems more likely that I would be passing through Brunswick instead of you going through Eastport, I will make the effort to arrange a meeting whenever time and conditions permit.

Sincerely,

Normand Laberge

Normand Laberge

cc: Prof. Arthur Johnson
Colonel Max. B. Scheider
Dr. John Joseph

during the first year

- the so-called Laberge method indicates a change due to the calculation of a different value for "d" for each succeeding year

- Figure 1 illustrates this difference in the dynamic behavior for the analysis performed in Table 2

- in this case, the sum of $\hat{C}_{2t}/(1+d)^t$ does not equal C_0 which violates the requirement that $PV_C' = PV_C''$

The Freeman and Laberge results for this example are quite different both in terms of cumulative figures and yearly totals. The fact that the sum of $\hat{C}_{2t}/(1+d)^t$ is not equal to C_0 brings out an additional question on how the present value calculations should be interpreted under the conditions assumed for Table 2.

After having the background information for my methodology, I am now prepared to make a case for its correctness. The first point refers to the selection of the various discount rates. The Corps of Engineers in their report assumed the cost of money at 6.875 % for the tidal project and 10.50 % for combined cycle plant. The selection of these rates must represent economic conditions during that year which necessarily assumes a certain inflation rate *. The calculations noted in Table 1 were performed for a 8 % rate of return, 2 % inflation rate, and a 10.16 % discount rate. Obviously, the selection of a discount rate of 10.16 % per year intrinsically assumed an inflation rate of 2 %/year. The so-called Freeman method doesn't seem to differentiate between the cases of no inflation (PC') and inflation (PC") since the results are the same regardless of the rate of inflation. But on the other hand, the so-called Laberge method will produce different results if the discount rate varies during the period of interest (see Table 2). In summary, the discount rate is functionally dependent on inflation, whereas, the rate of return is assumed to be independent of inflation for these calculations.

Since C_{2t} is not equal to $\hat{C}_{2t}$, what should be the annual fixed cost (or accounting artifact) for the project's financing ? The selection of $\hat{C}_{2t}$ seems to be the most logical choice for this discussion since it does represent the true cost of financing a project. By factoring out inflation in the calculation of present value, the expression for C_{2t} then becomes meaningless in terms of representing the actual expenses for this theoretical example. The calculation of $\hat{C}_{2t}$ is still restricted by the condition that the sum of $\hat{C}_{2t}/(1+d)^t$ is equal to C_0, but it does give a different time dependent behavior (see Figure 1). The behavior for $\hat{C}_{2t}/(1+d)^t$ versus time would be different if other values had been used for "r" and "i" and also for "T". No attempt was made at developing a normalized expression.

* the different discount rates is probably due to the different risk factor involved between private and public financing

TABLE 1

YEAR	r	i	d	C_{2t}	$C_{2t}/(1+r)^t$
FREEMAN					
1	8	2	10.16	.1490 C_0	.1380 C_0
2					.1278
3					.1183
4					.1095
5					.1014
6					.0939
7					.0870
8					.0805
9					.0746
10					.0690
				1.4900 C_0	1.0000 C_0

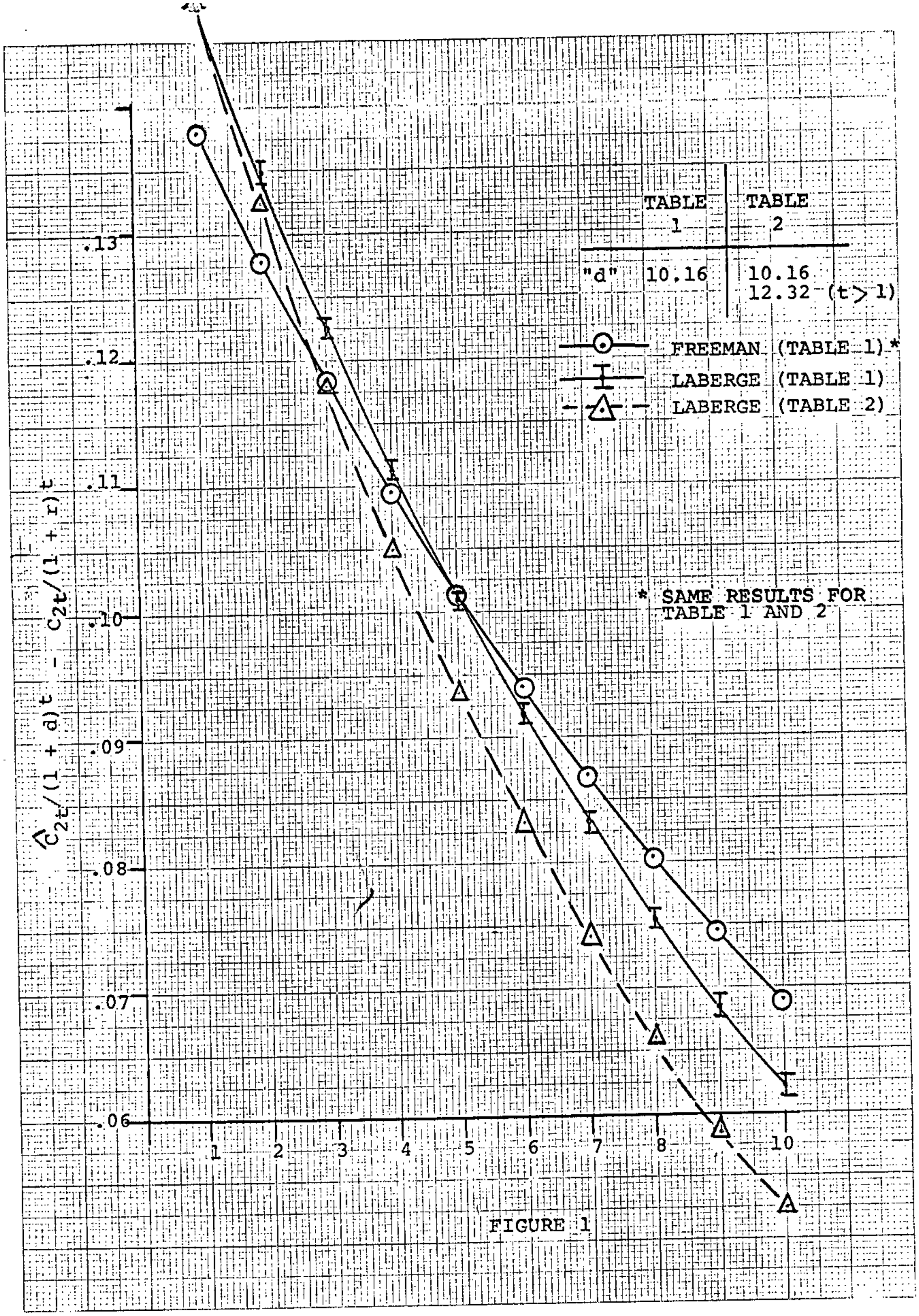
	r	i	d	$\hat{C}_{2t}$	$\hat{C}_{2t}/(1+d)^t$
LABERGE					
1	8	2	10.16	.1639 C_0	.1488 C_0
2					.1350
3					.1226
4					.1113
5					.1010
6					.0917
7					.0832
8					.0756
9					.0686
10					.0622
				1.6390 C_0	1.0000 C_0

NOTE: IF I=0, THEN THE TWO RESULTS ARE IDENTICAL; HOWEVER, WITH INFLATION THE BEHAVIOR OF THE TWO FUNCITONS ARE DIFFERENT (SEE FIGURE 1)

TABLE 2

YEAR	r	i	d	C_{2t}	$C_{2t}/(1+r)^t$
FREEMAN					
1	8	2	10.16	.1490 C_0	.1380 C_0
2		4	12.32	.1490 C_0	.1278 C_0
3					.1183 C_0
4					.1095 C_0
5					.1014 C_0
6					.0939 C_0
7					.0870 C_0
8					.0805 C_0
9					.0746 C_0
10					.0690 C_0
				1.4900 C_0	1.0000 C_0

YEAR	r	i	d	C_{2t}	$C_{2t}/(1+d)^t$
LABERGE					
1	8	2	10.16	.1639 C_0	.1488 C_0
2		4	12.32	.1639 C_0	.1324 C_0
3					.1179 C_0
4					.1050 C_0
5					.0935 C_0
6					.0832 C_0
7					.0741 C_0
8					.0660 C_0
9					.0587 C_0
10					.0523 C_0
				1.639 C_0	0.9319 C_0



$\hat{C}_{2t}/(1 + d)^t - C_{2t}/(1 + r)^t$
.13
.12
.11
.10
.09
.08
.07
.06
1
2
3
4
5
6
7
8
10
TABLE 1
TABLE 2
"d"
10.16
10.16
12.32 (t > 1)
FREEMAN (TABLE 1)*
LABERGE (TABLE 1)
LABERGE (TABLE 2)
* SAME RESULTS FOR TABLE 1 AND 2

FIGURE 1

EXHIBIT -A

W/ INFLATION

	LABERGE (A)	FREEMAN (B)
1.	$PV_c'' = \sum \frac{C_t(1+i)^t}{(1+d)^t}$	$PV_c'' = \sum \frac{C_t(1+i)^t}{(1+d)^t}$
2.	$C_t(1+i)^t = C_{1t}(1+i)^t + \hat{C}_{2t}$	$C_t(1+i)^t = C_{1t}(1+i)^t + C_{2t}(1+i)^t$
3.	WHERE $\hat{C}_{2t} = \frac{C_0 d(1+d)^T}{(1+d)^T - 1}$	$C_{2t} = \frac{C_0 r(1+r)^T}{(1+r)^T - 1}$
	THEN	
4.	$PV_c'' = \frac{\sum C_{1t}(1+i)^t}{(1+d)^t} + \frac{\sum \hat{C}_{2t}}{(1+d)^t}$	$PV_c'' = \sum \frac{C_{1t}(1+i)^t}{(1+d)^t} + \sum \frac{C_{2t}(1+i)^t}{(1+d)^t}$
5.	$= \sum \frac{C_{1t}(1+i)^t}{(1+r)^t(1+i)^t} + \sum \frac{\hat{C}_{2t}}{(1+d)^t}$	$= \sum \frac{C_{1t}(1+i)^t}{(1+r)^t(1+i)^t} + \sum \frac{C_{2t}(1+i)^t}{(1+r)^t(1+i)^t}$
6.	$= \sum \frac{C_{1t}}{(1+r)^t} + \sum \frac{\hat{C}_{2t}}{(1+d)^t}$	$= \sum \frac{C_{1t}}{(1+r)^t} + \sum \frac{C_{2t}}{(1+r)^t}$
7.	WHERE $C_0 = \sum \frac{\hat{C}_{2t}}{(1+d)^t}$	$C_0 = \sum \frac{C_{2t}}{(1+r)^t}$
	THEN,	
8.	$PV_c'' \equiv PV_c'$	$PV_c'' \equiv PV_c'$
	NOTE:	
9	$(1+d)^t = (1+r)^t(1+i)^t$	

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